DTU Library

The DES-Model and Its Applications

Grohnheit, Poul Erik

Publication date:
1986

Document Version
Publisher's PDF, also known as Version of record

Link back to DTU Orbit

Citation (APA):
Grohnheit, P. E. (1986). *The DES-Model and Its Applications*. Risø National Laboratory. Denmark. Forskningscenter Risoe. Risoe-R No. 519

DK8600114

RISØ

Risø-R-519

The DES-Model and Its Applications

Poul Erik Grohnheit

Risø National Laboratory, DK-4000 Roskilde, Denmark
May 1986

RISØ-R-519

THE DES-MODEL AND ITS APPLICATIONS

Poul Erik Grohnheit

Abstract: This report describes the use of the Danish Energy System (DES) Model, which has been used for several years as the most comprehensive model for the energy planning. The structure of the Danish energy system is described, and a number of energy system parameters are explained, in particular the efficiencies and marginal costs of combined heat and power (CHP). Some associated models are briefly outlined, and the use of the model is described by examples concerning scenarios for the primary energy requirements and energy system costs up to the year 2000, planned development of the power and heating systems, assessment of nuclear power, and effects of changes in the energy supply system on the emissions of SO_2 and NO_x.

May 1986
Risø National Laboratory, DK-4000 Roskilde, Denmark

Acknowledgements: Parts of the model descriptions are based on work by Frits Møller Andersen, Peter Skjerk Christensen, Helge V. Larsen, and Poul Erik Morthorst of the Energy Systems Group, Risø National Laboratory; and parts of Chapters 3 and 4 has been written i collaboration with Peter Laut of the Danish Engineering Academy. However, all responsibility for the use of these contributions is the author's.

ISBN 87-550-1224-8
ISSN 0106-2840

Grafisk Service, Risø 1986

CONTENTS

Page

1. INTRODUCTION

In recent years energy system models have played an increasingly important role in the energy planning carried out for and by public authorities, energy utilities, oil companies, etc. In particular, simulation models have emerged as a useful energy planning tool for the assessment of various aspects of the technical and economic behaviour of existing and future energy systems, e.g. forecasting of energy demand, planning of investments, and determination of operating strategies.

A number of simulation models have been used in official Danish energy planning, which is carried out by the Ministry of Energy with cooperation from the Danish Energy Agency and Risø National Laboratory as well as other ministries, public and semi-public institutions. The Energy Systems Group of Risø National Laboratory has been involved in most of these model activities since the late 70s, first of all through the development and use of the DES-Model (Danish Energy System), which gives a simplified but rather detailed description of the energy system as a whole. In addition to this model, simulation models have been developed and used which cover parts of the energy system or different energy demand sectors.

In this report the DES-Model and some associated models are presented in the context of a description of the Danish energy system and on the basis of the use of the models for energy planning. The examples presented in the tables and figures are from different sources and different versions of the DES-Model, and they do not claim to present a comprehensive picture of the Danish energy system.

1.1. The DES-Model

The DES-Model is a model system for translating energy demand forecasts into annual primary energy requirements, energy system costs, and selected environmental consequences.

Part of the model was originally developed by the electrical utility ELKRAFT in the early 70s and named Long-term Planning System (LPS). The purpose of this model was the simulation of the operation of a system of power stations that includes Combined Heat and Power Generation (CHP), together with calculations of the running costs. This model was redesigned and extended by Risø for use in a study of electrical heating by adding a module that calculates the economic consequences of the demand for space heating produced by CHP, natural gas, or electrical heating.

The model is used as the most comprehensive for the Danish energy planning. This includes the use of the model for the evaluation of the different scenarios described in the Energy Plan 81, the scenarios for the Energy Reviews 1983 and 1984, and, most recently, it is being used for Energy Plan 86. (Ministry of Energy 1981, 1983, 1984). It has also been used for several partial studies of the energy system, e.g. the economic assessment of nuclear power, the environmental consequences of energy system changes, and scenarios for long-term consequences of the technological development.

The model describes a system of energy conversion units that connects the demands for various types of useful energy through intermediate energy products to the requirements for various types of fuels. It may be used for calculations of scenarios describing the development of the energy system for a period of up to 40 years, covering the lifetime of large technical equipment; or, a number of scenarios that are alternatives to a reference scenario may be calculated for a selected year.

Given a set of forecasts for the demand for useful energy, energy prices, and the development of the conversion and distribution system, the model produces detailed results of the structure of the future energy supply system including the primary energy requirements, the costs of the energy systems, and selected environmental consequences.

It is an important feature of the energy system that most types of energy demand can be satisfied from several sources. The most obvious examples are electricity and district heating. For these competing conversion units a merit order must be specified by the user which leaves some types of conversion units as residuals. The calculated productions from these residual conversion units are essential for the evaluation of the feasibility and acceptability of the simulation results.

The power system with CHP is the most important subsystem of competing units. The variation in the power demand is described by half year load duration curves, and the generating units are scheduled in merit order according to their variable costs, giving a very simplified calculation of the fuel requirements.

The structure of the DES-Model reflects the main points of interest of Danish energy policy in recent years. These include the development of the power system, extension of the district heating system with CHP and surplus heat, introduction of natural gas, heat planning, and the use of renewables and local energy resources. The transport and process sectors are very simplified, and the refinery sector is not included.

The model is used for scenarios that are described by a large number of exogenous variables.

The elements and structure of the model is described in Chapter 2. The most important power system parameters used in the model are discussed in Chapter 3, and the use of the model for the power system is considered in Chapter 4. The rest of the energy system is described in Chapter 5. The exogenous variables for the scenarios and the results are described in Chapter 6, and a study in which the model is used to calculate emissions of pollutants is the subject of Chapter 7.

1.2. The Simulachron model

A more thorough simulation of the CHP system, which takes into account the simultaneous variations of the power and heat loads, is done by the Simulachron model. This model describes in a detailed way technical and economic aspects of a national CHP production system including various types of power plants, district heating boilers, and day-to-day heat storage facilities. In the Simulachron model load dispatch among the available units is simulated for a number of short periods (e.g. 3 days) with different demand variations for electricity and heat loads. A year is composed of an appropriate selection of these periods representing seasonal demand variations and variations in the available generating capacity. The model is described in Section 4.2, and an example of the use of the model is given in Section 4.5.

1.3. Demand forecast models

The demand for useful energy is divided into four sectors: Process, transport, space heating, and non-substitutable electricity. Forecasts for the demands in these sectors are built up using various methods, and in some subsectors more elaborate simulation models are used, e.g. a technical-economic model for energy consumption by industry and a vintage-stock forecasting model for the electricity demand from domestic appliances. These models are described in Section 6.1.

1.4. The European DESS-Model

The principles and structure of the DES-Model may be used for other countries, although the relative importance of the various subsystems will be different. By the end of 1985, work on the development of a European version of the model was started under contract with the Commission of the European Communities. The general objective of this project is the development of a Detailed Energy System Simulation (DESS) model for the EC countries on the basis of the software and model structure of the DES-Model, which include a detailed technico-economic description of the energy producing and transformation units, in particular the power generation units as well as district heating and conversion technologies for a period of 20-30 years.

2. ESSENTIALS OF THE DES-MODEL

2.1. Energy conversion units and efficiencies

The DES-Model describes a system of energy conversion units that connects the demands for various types of useful energy through intermediate energy products to the requirements for various types of fuels. These conversion units may be specific power stations, types of district heating plant, transmission and distribution grids, or typical heating systems for single family houses. The principle is shown in Fig. 2.1; the information flow goes from left to right, while the physical flow goes from right to left.

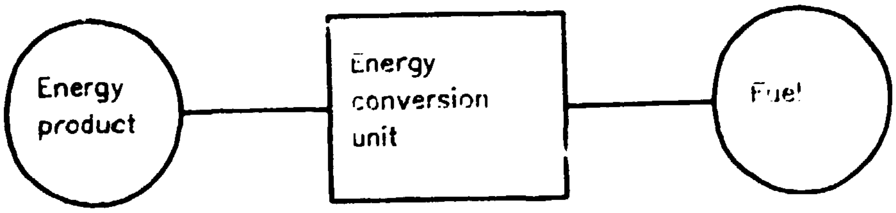

Fig. 2.1. Energy conversion unit

Each of these elements is described by

- type of energy output
- type of energy input
- capacity
- efficiency, i.e. output per unit input
- investment costs
- annual operating costs
- emission factors for pollutants

In the DES-Model a network of energy conversion units is built up consisting of the most important categories of conversion units and the most important energy flows between the demands for useful energy, intermediate energy products, and primary requirements. This is illustrated in Fig. 2.2 for the Danish energy system. The energy conversion units that belong to the solid-line boxes are included in the DES-Model, while those belonging to the broken-line boxes have not yet been included.

The fuel requirements for the different energy uses are most often calculated by the model from the amount of energy divided by one or more energy efficiency rates that are assumed for the various energy conversion units.

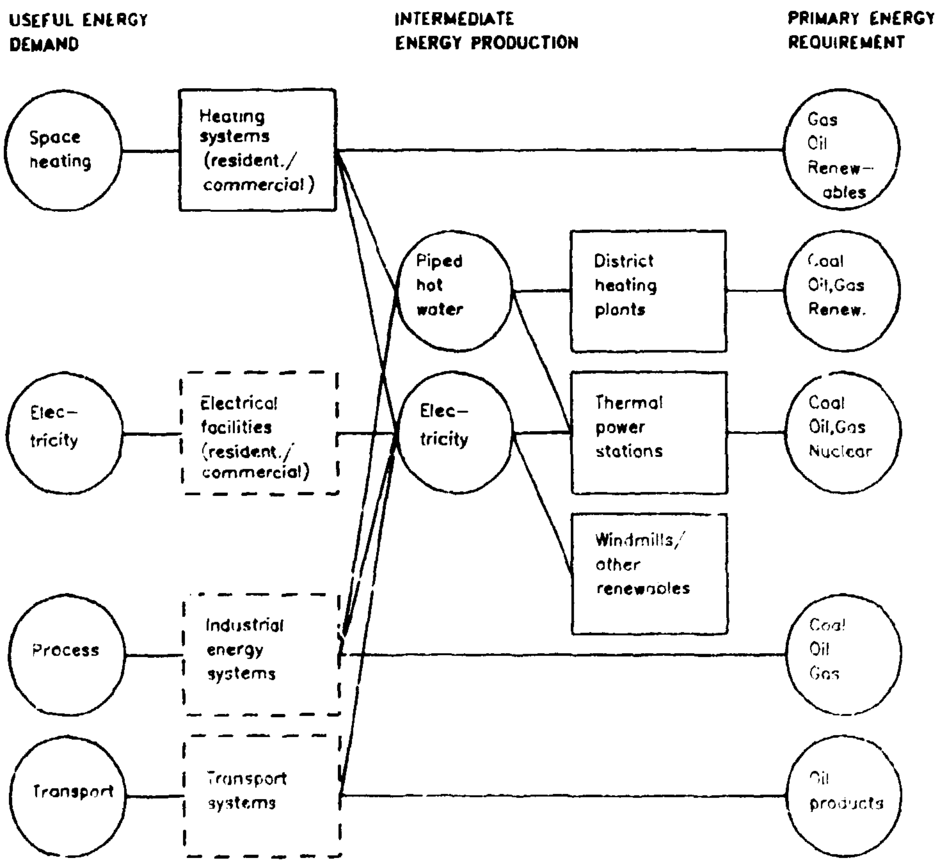

Fig. 2.2. The energy flows of the DES-Model

For process and transport energy, however, there exists no generally accepted concept of useful energy. Therefore, energy consumption in these sectors must be expressed by the fuel requirements.

Electricity may be measured at the final consumer or from the plant, the difference being the transmission and distribution losses. This is expressed in the model by the efficiency, e.g. 0.9. As the electricity system is a network of interconnected power generating units, which may produce by different fuels and at very different efficiencies, it is necessary to include the whole system when calculating the fuel requirement for electricity production. In the DES-Model this is done by a submodel for the power system with CHP.

The fuel requirements for space heating are calculated from the demand for useful energy at the radiator or the hot water tap divided by the efficiencies of the conversion units that are included in the heating system.

2.2. The power system with CHP

The simulation of the electricity and heat supply from thermal power stations is a central part of the model. This simulation is based on the following features:

- Each generating unit or type of units is described by simplified data: Maximum electricity and heat output, fuel type, efficiency, availability, and operation costs,
- the variation in the annual electricity demand is described by load duration curves for winter and summer, and
- the heat demands in each CHP-region are specified for winter and summer.

As the generating units are scheduled in merit order according to their variable costs, base load is supplied by the units producing at lowest cost, and peak load by those producing at higher costs. The results of the simulation will be the annual electricity and heat output for each unit or type of units, and the fuel and operating costs of these units. These results are aggregated into groups of units characterized by fuel type, CHP-supply, flue gas desulphurization facilities (FGD), etc.

The annual production from wind turbines is calculated from a forecast both of their number and unit production. The demand for power from thermal stations is reduced accordingly, and the load duration curve is modified. Hydro power may be included as a special power unit, or, like wind power, by reducing the demand from thermal stations.

2.3. Other competing supply units

For the simulation of the annual supply of district heating in Denmark, priorities are given to urban waste incineration, co-generated heat from power stations, and natural gas according to the national energy planning objectives, leaving the utilizations of coal and oil-fired district heating plants as residuals.

The heat supply of single-family dwellings is simulated in the same way with priorities to district heating and natural gas, leaving the number of individual oil furnaces as a residual.

2.4. Module structure and software

The DES-Model is composed of modules for energy subsystems with suitable interface variables; each module consists of energy data and submodels of varying complexity, ranging from simple accountancy assignments to the simulation model for the electricity generating system with CHP.

Each module of the model is divided into model-phases, which are logical units consisting of above-mentioned elements. A phase may be calculated separately for all years or in line with other phases.

The software is a special purpose FORTRAN-program developed in the early 70s, but improved and modified during the use of the model. Recently, a transcription of the program, which was written in FORTRAN 66, to FORTRAN 77 has been done. This transcription is a part of the work for a European version of the model, and it will facilitate the implementation of the model for other countries and the transfer to other computers.

2.5. Scenario calculations

The input data for the scenarios must consist of forecasts or planning assumptions for

- all useful energy demands,
- prices for all types of primary energy, and
- numbers of units or total capacities of selected types of conversion units

The output data of the model simulation consist of

- numbers of units, total capacities, or utilization times for residual types of conversion units, i.e. those not selected above,
- primary energy requirements for each energy type,
- investment, operation, and fuel costs, and
- emissions of pollutants.

The output data for the residual conversion units are essential for evaluating the feasibility of the simulation results.

These residual conversion units may be gas turbines in the power system, and oil-fired district heating plants, or individual oil-fired furnaces in the heating system.

The model may be used either for calculations of scenarios for the development of the energy system for a period up to 40 years, or a number of scenario alternatives to a reference scenario for a selected year in the future.

Figure 2.3 describes the model structure which is used for the studies for the Ministry of Energy. The blocks denote modules or model-phases consisting of basic parameters, assignments and functions. The circles denote exogenous input data, or output tables etc. The input data consist of forecasts of energy demand, development plans for the supply system, and economic or technical parameters.

In the first phase a description of the stock of power stations is established for each year in the planning period. Old units are taken out and new ones are put into operation according to a development plan.

In the next phase electricity production from windmills and biogas installations is subtracted from the total demand, and the required production from thermal stations is found. Forecasts of the heat demand in each area with district heating supplied by CHP are given, and the fuel requirement for the power system is found. Then the annual expenditures for investment, fuel, and operation are calculated.

The space-heating demand is calculated in the next phase as the products of the forecasts for future building areas and useful energy demand per unit area in buildings. Then the distributions of heating forms and primary energy requirements for space heating are calculated. The supply of district heating from CHP is known from the electricity sector of the model. District heating supplied by waste incineration, coal and natural gas as well as individual heating supplied by electricity, natural gas, and renewables (wind, biogas, straw, heat pumps etc.) are all given as forecasts. The rest of the heat demand is supplied by oil.

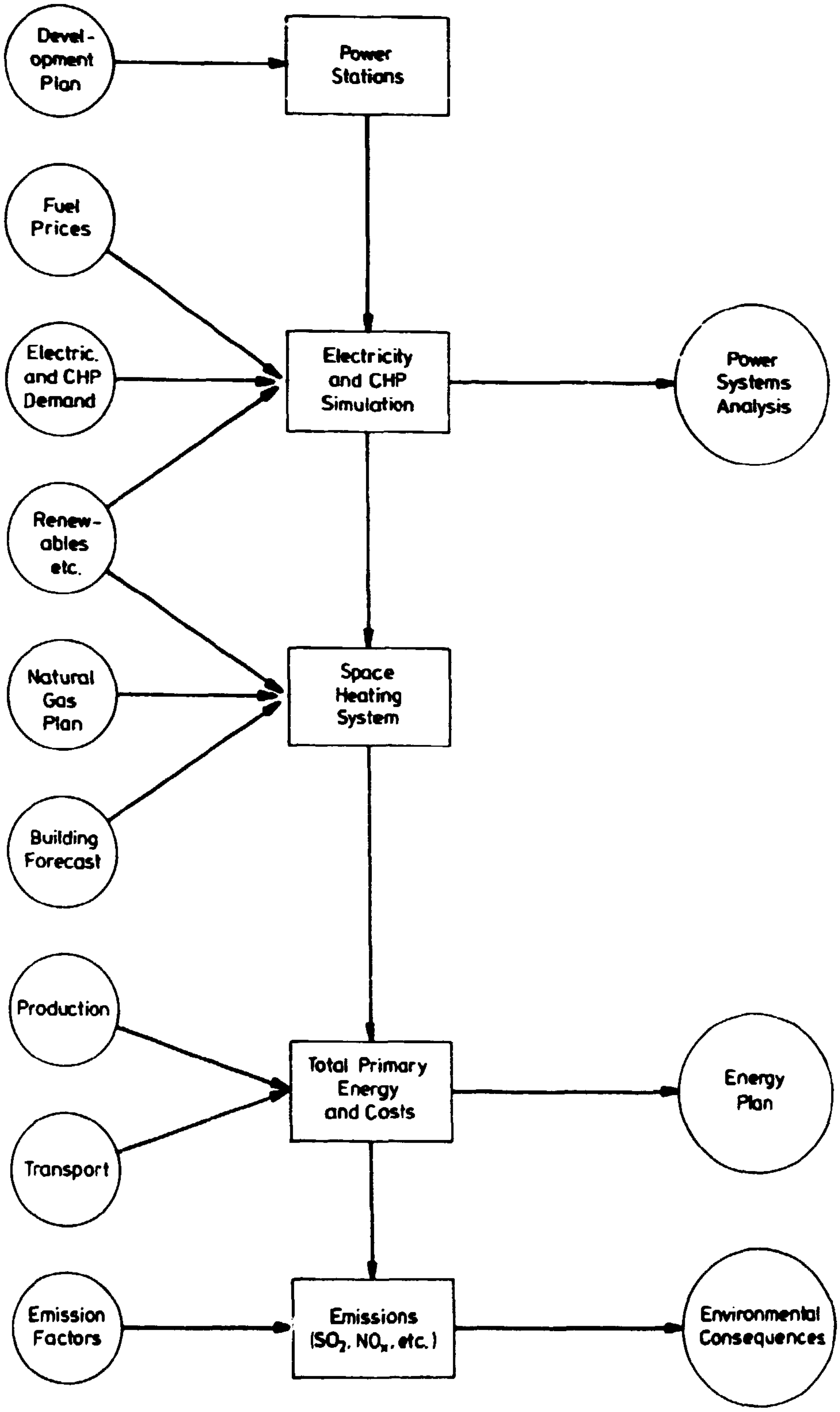

Fig. 2.3. The DES-Model

The fuel demands in the production and transport sectors are added in the following phase, and the primary energy requirement for all sectors by fuel types is found together with the annual costs.

In the last phase selected environmental consequences are calculated. Given the primary energy demand in sectors relevant for environmental analysis, the emissions of SO_2, NO_x, CO and particles are calculated together with the costs in each sector using emission factors for each fuel type and each type of conversion.

3. POWER SYSTEM EFFICIENCIES AND FUEL COSTS

3.1. The power system with cogeneration

Cogeneration is the combined production of heat for local use and electricity for the national and international electrical grid; it is an important feature of the Danish power system, where the cogenerated heat is used for district heating. Electricity in Denmark is produced almost entirely from fossil fuel, nearly all of which is coal. Three types of turbines are used:

- condensing turbines without cogeneration,
- back-pressure turbines producing power and heat in a fixed ratio given by the technical lay-out of the turbine, and
- extraction turbines which allow both condensing and back-pressure mode production in a flexible combination of power and heat.

Heat for district heating is produced within a number of heat regions. Apart from being cogenerated with electricity heat may be supplied from waste incineration plants, industrial excess heat, or district heating plants using coal, oil, natural gas, or biomass. Industrial cogeneration is little used in Denmark.

3.2. Merit order and efficiencies of power generating units

The demand for power during a time period is met by supply from the available power generating units in merit order, i.e. units with lower variable costs are preferred to those with higher costs. The variable costs - or more exactly short-run marginal costs - (m) are calculated from fuel prices (f), marginal efficiencies of generating units (η), and variable operating costs (k)

$$m = f/\eta + k \tag{1}$$

the most important parameters being the fuel prices and efficiencies, while the variable operating costs are normally relatively small.

The merit order is easily set up for condensing units producing electricity only. In case of combined production, however, the merit order must be determined by considering the whole power and heat producing system, or an appropriate marginal segment of that system.

Figure 3.1 shows a simplified, linear representation of the limits of feasible combinations of power and heat production for an extraction turbine, and lines of output combinations at constant fuel input for this turbine. In a simulation model for the power system any point within the polygon will be considered as a combination of back-pressure and condensing production. For back-pressure turbines only combinations on the back-pressure line are feasible.

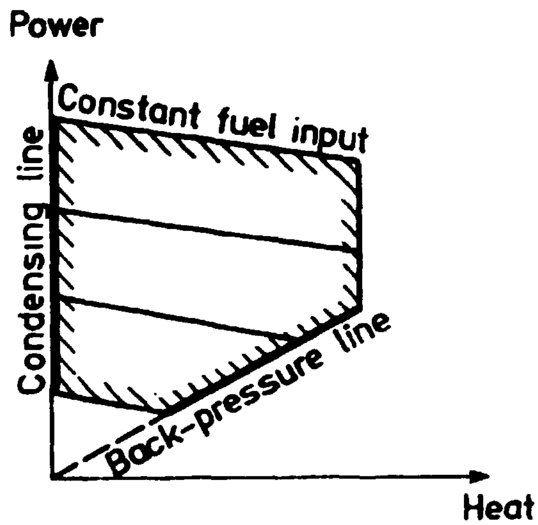

Fig. 3.1. Limits of power and heat production from extraction turbines.

The short-run marginal cost of electricity production utilizing back-pressure mode is determined as:

> The cost of the combined production of electricity and heat minus the costs of the alternative, separate production of heat for the district heating grid.

The production of heat which is the alternative to CHP is assumed to be by coal-fired district heating boilers, which should correspond to the future situation in Denmark.

Thus defined, the marginal costs per kWh of electricity produced in combination with heat can be expressed as

$$m_p^{CHP} = f_{coal}/\eta_p^{CHP} + k^{CHP} \qquad (2)$$

with

$$\eta_p^{CHP} = \left[\frac{1 + c_v/c_m}{\eta_p} - \frac{1}{c_m \eta_h} \right]^{-1} \qquad (3)$$

and

η_p the efficiency, i.e. electricity produced per unit fuel, at condensing mode

c_v reduction of electricity production per unit of heat produced at back-pressure mode (negative slope of the constant fuel input line of Fig. 3.1)

c_m electricity production per unit heat production at back-pressure mode (the slope of the back-pressure line of Fig. 3.1)

η_h the effciency, i.e. heat production per unit fuel, of district heating boilers.

In order to arrive at the simple expression (2) we assume the same coal price for all units regardless of size.

For modern plants in Denmark the following parameter values are representative:

$$\eta_p = 0.413,\ c_v = 0.181,\ c_m = 0.630, \text{ and } \eta_h = 0.830,$$

and thus

$$\eta_p^{CHP} = 0.83.$$

The efficiencies are equivalent to the following heat rates, i.e. fuel consumption per unit power:

for condensing mode	8.70 MJ/kWh, and
for back-pressure mode	4.33 MJ/kWh.

The efficiency parameters are described in detail in Sections 3.3 and 3.4, below.

3.3. Cogeneration efficiencies and system limitations

Figure 3.2 shows a more abstract representation than does Fig. 3.1 of a power and heat producing system that includes capacities for both separate and combined production of power and heat. The point P is the power output of one fuel unit from condensing production by an extraction or condensing unit that is connected to the national electrical grid. Point H is the heat output from a district heating boiler that is connected to the same urban district heating grid as the CHP-unit. Finally, point M represents the power and heat output of any segment of the back-pressure line of Fig. 3.1 corresponding to a marginal input of one fuel unit. Line PH shows the output combinations of one fuel unit for a system with separate production only. When back-pressure production is available within the system, however, the output of heat and power may be increased to line PMH, where back-pressure production is used in combination with either condensing power production or heat production from district heating boilers.

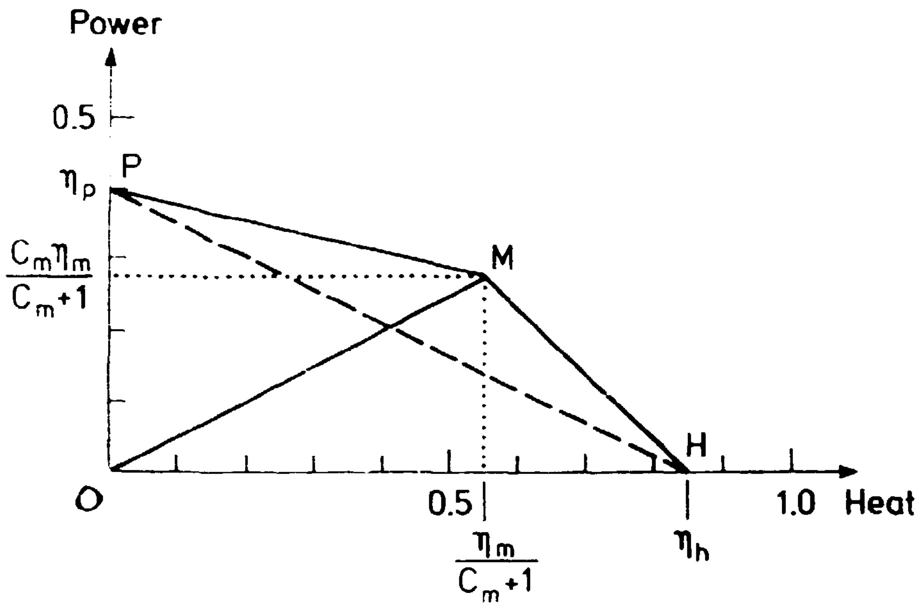

Fig 3.2. Power and heat output from a fuel unit by cogeneration or separate production

The following parameter is added to describe the system:

η_m the efficiency, i.e. electricity plus heat per unit fuel, at back-pressure mode.

The values of the parameters that are illustrated in Fig. 3.2 describe the marginal situation expected in the Danish energy system during the 90s in ordinary demand and supply situations.

The fuel requirement (F_i) for each of the three types of conversion can be expressed by the power (P_i) and heat (H_i) outputs:

Condensing production $F_1 = P_1/\eta_p$ (4)

Back-pressure production $F_2 = (P_2 + H_2)/\eta_m$, $P_2 = c_m H_2$ (5)

District heating boilers $F_3 = H_3/\eta_h$ (6)

The total demands for power (P) within a power system and heat (H) within a heat region are:

$$P = P_1 + P_2 \text{ and } H = H_2 + H_3$$

The variable costs of the system at fuel prices equal to unity and zero operating costs can be expressed in several equivalent ways:

$$C = F_1 + F_2 + F_3 \qquad (7)$$

$$= \frac{P}{\eta_p} + \frac{H}{\eta_h} - \left(\frac{c_m}{\eta_p} - \frac{c_m+1}{\eta_m} + \frac{1}{\eta_h}\right)\frac{P_2}{c_m}$$

$$= \frac{P_1}{\eta_p} + \frac{P_2}{\eta_p^{CHP}} + \frac{H}{\eta_h}$$

$$= \frac{P}{\eta_p} + \frac{H_2}{\eta_h^{CHP}} + \frac{H_3}{\eta_h}$$

where

$$\eta_p^{CHP} = \left[\frac{c_m+1}{c_m\ \eta_m} - \frac{1}{c_m\ \eta_h}\right]^{-1} \qquad (8)$$

is the efficiency of cogenerated power for a given output of heat, and

$$\eta_h^{CHP} = \frac{\eta_p}{c_v} = \left[\frac{1}{\eta_m} - \left(\frac{1}{\eta_p} - \frac{1}{\eta_m}\right)c_m\right]^{-1} \qquad (9)$$

is the efficiency of cogenerated heat for a given output of power. The parameter c_v is the absolute value of the slope of the line PM in Fig. 3.2, representing the loss of at increased heat production. While

$$c_v = \frac{\eta_p}{\eta_m} - \left(1 - \frac{\eta_p}{\eta_m}\right) c_m \qquad (10)$$

it can be shown that the expression at the right side of Equation (8) is identical to that of Equation (3).

As $\eta_m \approx \eta_h$ and $\eta_p < \eta_m$, it follows that $\eta_p^{CHP} > \eta_p$ and $\eta_h^{CHP} > \eta_h$. Therefore, the lowest variable cost is found at maximum cogeneration subject to the limitations of the heat and power system. The efficiency of cogenerated power η_p^{CHP} is used to determine the merit order of power generating units, assuming that the benefit of cogeneration is assigned to power.

A graphical interpretation of these efficiencies is shown in Fig. 3.3. The net output of the marginal unit of fuel is made up of the increased combined production OM' and the reduced heat production at reference district heating boilers M'P', the value of η_p^{CHP} being about 0.85. The efficiency of cogenerated heat η_h^{CHP} is correspondingly made up of an increased combined production OM" and a reduced power production at reference condensing power plants M"H', the value of η_h^{CHP} being about 2.0 and the value of c_v about 0.2. It is, however, highly sensitive to the basic parameters. It can be seen that the values of η_p^{CHP} and η_h^{CHP} are found if lines HM and PM in Fig. 3.3 are extended to intersect the axes.

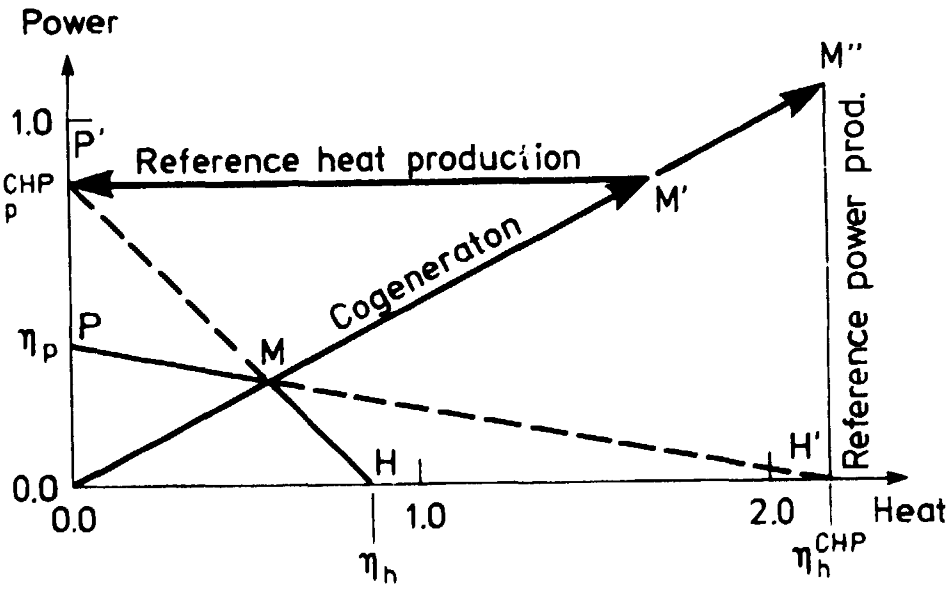

Fig. 3.3. Cogeneration efficiencies

For heat region i, H_i is the heat demand and H_{2i}^{max} the heat capacity of the CHP-units; thus, the maximum cogenerated heat is

$$H_{2i} < \min \{H_{2i}^{max}, H_i\} \quad i = (1,\ldots.n), \text{ and} \tag{11}$$

$$H_2 = \sum_i H_{2i} < P/c_m \tag{12}$$

i.e. cogenerated heat cannot exceed the capacity or demand in each heat region, and the total cogenerated heat cannot exceed the heat prodution that corresponds to the total power demand.

The maximum cogenerated power is determined by the limitations of the heating system; thus

$$P_2 < c_m H_2 \tag{13}$$

3.4. Unit and system efficiencies

The parameters of the various units in the power system may be different. The efficiencies of cogeneration for a particular CHP-unit are therefore dependent both on the parameters of the unit itself, c_m and η_m, and those of the reference production, η_h and η_p. Fuel prices are assumed equal to unity, i.e. fuel price differences are either negligitable, or efficiencies must be corrected for fuel price differences.

The efficiency of the reference condensing production, η_p, is representative of the marginal condensing unit within the power system. If this system consists of units with different efficiencies, the marginal efficiency may vary considerably, depending on the load of the total system; thus, the cogeneration efficiencies for a longer period is found as the average of short-period efficiencies.

The formulas developed so far can be applied without further modification for back-pressure units. For extraction units, however, some further modifications are needed: If condensing mode production at an extraction unit is more efficient than the marginal condensing unit in the power system, this extraction unit will be allowed to produce at its full capacity. When back-pressure production at this unit is increased, its power production is reduced and must be replaced by production at the marginal condensing unit, thus reducing the system efficiencies of cogeneration.

Let η_p^T and η_m^T be the efficiencies of condensing and back-pressure mode production at a particular extraction unit, we have, using Equations (4), and (5),

$$F_2 = \frac{P_2 + H_2}{\eta_m} = \frac{P_2 + H_2}{\eta_m^T} + \left(\frac{1}{\eta_p} - \frac{1}{\eta_p^T}\right)(P_2 + c_v^T H_2) \qquad (14)$$

where

$$P_2 = c_m H_2 \qquad (15)$$

and, using Equation (10),

$$c_v^T = \frac{\eta_p^T}{\eta_m^T} - \left(1 - \frac{\eta_p^T}{\eta_m^T}\right) c_m = (c_m + 1)\frac{\eta_p^T}{\eta_m^T} - c_m \qquad (16)$$

Inserting (15) and (16) into (14), we get an efficiency of back-pressure mode production that is corrected for the difference between condensing mode production at the extraction unit and the marginal condensing unit:

$$\eta_m = \eta_m^T \, \eta_p / \eta_p^T \quad , \quad \eta_p^T > \eta_p \qquad (17)$$

In Table 3.1 values of the system efficiences for power and heat of cogeneration are calculated using Equations (8) and (9). No modification is needed in the first three cases. In the last two cases the above-mentioned modification is applied. The basic parameters are within the range found in the Danish power system. As all plants are coal-fired, there are no significant fuel price differences.

Table 3.1. Marginal system parameters of cogeneration for coal-fired units.

Unit parameters:			η_p^{CHP}				η_h^{CHP}	
			η_h=0.80		η_h=0.85			
c_m	η_m^T	η_p^T	η_p=0.35	η_p=0.41	η_p=0.35	η_p=0.41	η_p=0.35	η_p=0.41
0.40	0.80		0.80	0.80	0.70	0.70	1.65	1.29
0.40	0.85		1.01	1.01	0.85	0.85	1.98	1.49
0.50	0.85		0.97	0.97	0.85	0.85	2.98	1.83
0.50	0.85	0.41	0.61	0.97	0.56	0.85	1.57	1.83
0.60	0.85	0.41	0.63	0.95	0.58	0.85	2.04	2.39

4. SIMULATION OF THE POWER SYSTEM

The production of power and heat must follow the variations of the demands, because storage possibilities are limited. For future periods the load dispatch among the various production units can be simulated using models of various complexity. A very simplified simulation of the annual production can be made using load duration curves (the DES-Model). A more thorough simulation can be made for a period of a few days using time steps of one or two hours to describe load variations, (the Simulachron model). None of these models, however, take into account the geographical distribution of the power stations and the capacity limits of the transmission grid.

4.1. The DES-Model

The simulation of the electricity and heat supply from thermal power stations is the most elaborate part of the DES-Model. This simulation is based on the following features:

- Each generating unit or type of units is described by simplified data: maximum electricity and heat output, fuel type, fuel requirements for start-ups, efficiencies (heat rates) for condensing and back-pressure generating modes, c_m-value (i.e. power per unit heat at back-pressure mode), kind of pollution abatement facilities, availability, operating and maintenance costs,
- the variation in the annual electricity demand is described by load duration curves for winter and summer,
- the heat demands in each CHP-region are specified for winter and summer,
- the annual electricity demand within the power system is specified by the maximum load demand and the load factor, and
- fuel prices are specified for each fuel type.

The annual demands of heat and power are satisfied in the most economical way using the following principles of load dispatching.

- The maximum power of each unit is corrected for unavailability, i.e. maintenance and break-down.
- A priority list is set up according to the variable costs (merit order). Extraction units are divided into back-pressure and condensing parts and placed at the appropriate positions in the merit order, taking into account the benifit from cogeneration.
- The units are placed under the load duration curve as bands from the bottom according to the priority list as shown in Fig. 4.1. If the list is exhausted before the demand is satisfied the remaining power may be provided by expensive production from a peak unit.

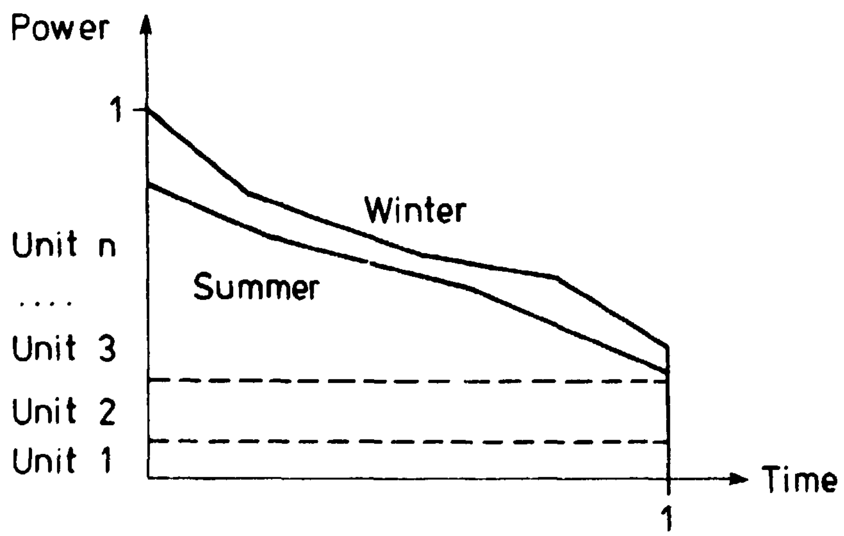

Fig. 4.1. Load duration curves for the electricity generating system, winter and summer.

The results of the simulation will be the annual electricity and heat output for each unit or type of units, and the fuel and operating costs of these units. These results are aggregated into groups of units characterized by fuel type, CHP-supply, flue gas desulphurization (FGD) facilities, etc.

The annual production from wind turbines is calculated from an estimate of their number and unit production. The demand for power from thermal stations is reduced accordingly, and the load duration curve is modified. Hydro power, which does not exist in Denmark, may be treated in the same way. Non-thermal production, however, may be specified in the model by production in the winter and summer half-years.

The model is designed for use in long-term planning studies, which means that a day-to-day commitment taking into account the hourly variation of the demand is of little interest. On the contrary, a quick, reasonably accurate calculation of the annual fuel and operation costs of the system is more important for this purpose.

4.2. The Simulachron model

A more thorough simulation of the CHP-system, which takes into account the simultaneous variations of the power and heat loads, is done by the Simulachron model. This model describes in a detailed way technical and economic aspects of a national CHP production system including condensing, extraction, and back-pressure power plants, district heating boilers, and day-to-day heat storage facilities. (Larsen 1984).

Simulachron is developed as a tool for the evaluation of development plans for the CHP production system on a national level. The model can also be used to model part of the system, or for evaluating the introduction of new technologies to the system, e.g. nuclear or wind power. Finally, the Simulachron model is used to estimate the more aggregate parameters of the DES-Model and to verify the feasibility of its results.

4.2.1. Time periods

A time period of arbitrary length divided into an arbitrary number of time steps can be simulated, e.g. three days divided into two-hour time steps. Heat and power demands are specified for each time step. The available conversion plants and heat storage facilities are specified for the time period as a whole, and the model simulates load dispatch among these facilities in order to minimize fuel and operating cost.

The simulation of heat and power production for a year is made up of simulations of a number of representative time periods, which reflect seasonal demand variations and unavailability of conversion plants.

4.2.2. Optimisation procedure

For the optimisation procedure of the model it is assumed that combined production has priority over condensing production. This assumption allows a sequential performance of the simulation: First, heat production is simulated in each heat region; then, the overall simulation of electricity is carried out.

Wind power may be included in the simulation of electricity by subtracting wind-generated electricity from the power demand, each of which is represented by a time series.

The main parts of the computer model are shown in Fig. 4.2.

4.2.3. Simulation of heat production

The heat demand of a heat region is dispatched among the heat-producing units for each time step. If there is heat storage within the heat region, the production can be moved from one time step to another within the limits of the storage.

For the heat load dispatch the value of the electricity production from back-pressure or extraction power plants is taken into account. This value is an exogenous time-dependent variable that might have been found in a previous simulation of the power production (see Section 4.2.5, below).

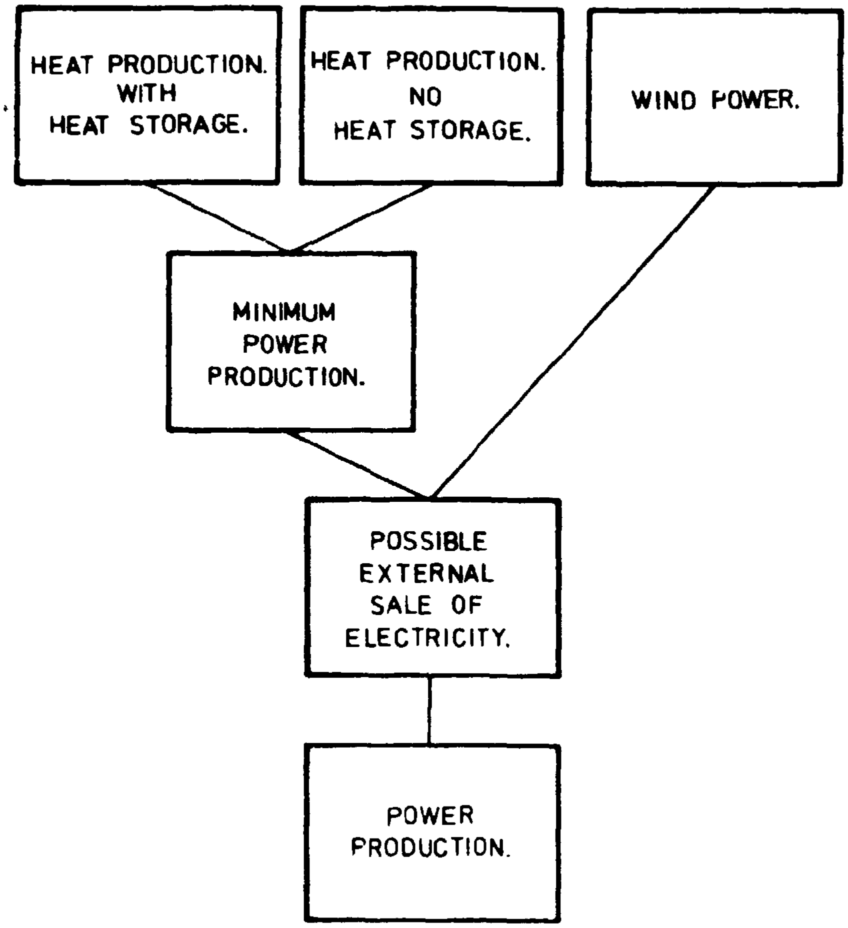

Fig. 4.2. Main parts of the Simulachron computer model

4.2.4. Interface between the modelling of the heat and power production

When the simulation of the heat production has been performed for all district heating areas, an overall simulation of the electricity production is carried out. During this latter simulation the heat production is left unchanged.

The simulated heat production determines a minimum power production below which the CHP units cannot be operated. For back-pressure power plants the power production is fixed when the heat production is given, while extraction units still have some operational flexibility.

If these minimum power productions are greater than the power demand, the excess production is assumed to be sold to some external power grid at a time-dependent price.

The price may be fixed exogenously as an expected contract price, or determined from the marginal cost of production found in the simulation of the power production.

4.2.5. Simulation of the power production

As mentioned above, back-pressure plants do not take part in this simulation, because their power production has been determined during the simulation of the heat production.

Extraction plants that are committed for heat production can be considered as condensing plants that have to produce power within a range given by the heat production as shown in Fig. 4.3.

The simulation of the power production consists of a simultaneous unit commitment and load dispatching. Unit commitments, i.e. whether a particular unit shall operate or not, are specified for each time step through zero-one variables. This integer variable is necessary, because there is a minimum level of production for each unit. Extraction plants that are comitted to produce heat are required to produce electricity as well.

In the load dispatching it is found for each time step how much power those units that are committed for operation should produce to minimize the costs.

One of the results of the load dispatching is a time series of marginal power costs. This time series is used for the simulation of heat production, which is then repeated. During this iteration process the value of the cogenerated electricity is found.

Condensing plants and extraction plants not committed for heat production can be operated within the interval given by minimum production and rated capacity.

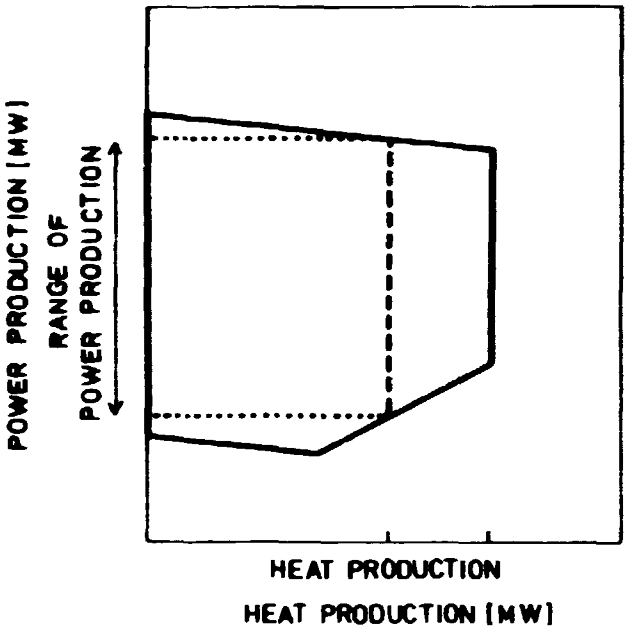

Fig. 4.3. The heat production determines the possible range of power production for an extraction unit

4.3. The Danish power system

4.3.1. Load variations

In the Simulachron model the load dispatch among the available units is simulated for a number of 3-day periods with different demand variations for electricity and heat given by two-hour time steps. Each 3-day period represents two weekdays and one week-end day or holiday. A year consists of 122 3-day periods, and it is composed by an appropriate selection of 3-day periods representing seasonal demand variations and variations in the availability of the various generating units.

A very simplified model year consists of 61 winter and 61 summer periods. In order to find two periods that appropriately would represent the load variations of the whole year, load curves for the four periods around the solstices (December and June) and equinoxes (March and September) were studied. Only small differences in load variation patterns were found between the curves for December and March and between the curves for June and September. Therefore, the curves for the periods around the equinoxes can be representative of the whole year, especially when studying the power system for a distant future.

In Fig. 4.4 the load variation patterns for March and September are shown. The relative load variations are based on experienced hourly values from the ELSAM area in 1977 to 1979 (ELSAM 1984). The absolute values are based on a forecast for the Danish power system for the year 2010 (Energiministeriet 1984a, 1984b). In the figure heat loads are shown as back-pressure power loads in order to show the importance of this mode of power production.

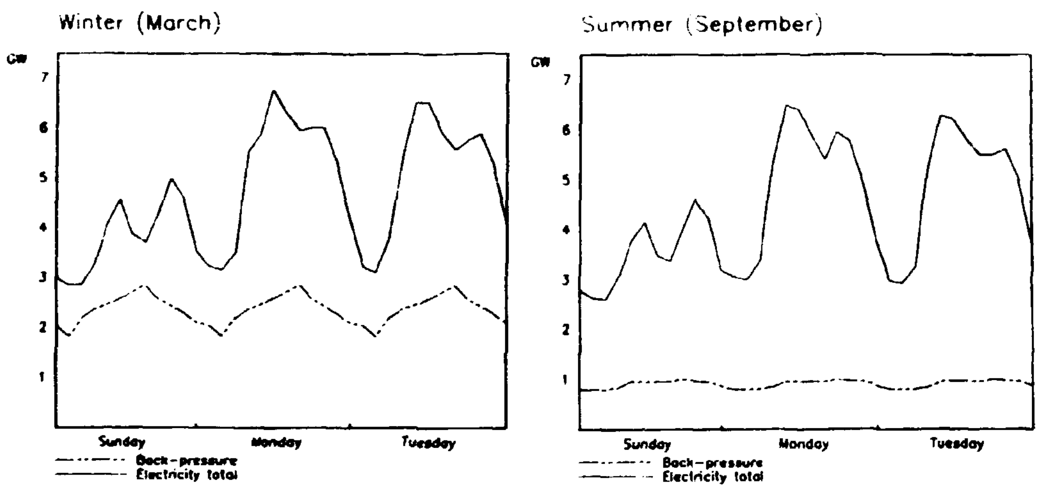

Fig. 4.4. Electricity and heat load variations

The corresponding load duration curves based on these data are shown in Fig. 4.5. As the generating units are scheduled in merit order according to their variable costs, base load is supplied by those units producing at lowest cost, and intermediate and peak loads by the ones producing at higher cost.

The projected electricity demand will correspond to a maximum load (winter peak) of 6.9 GW, the projected heat demand from CHP for the winter season to a constant back-pressure power production of 2.1 GW, and the projected wind production to an average load of 0.6 GW.

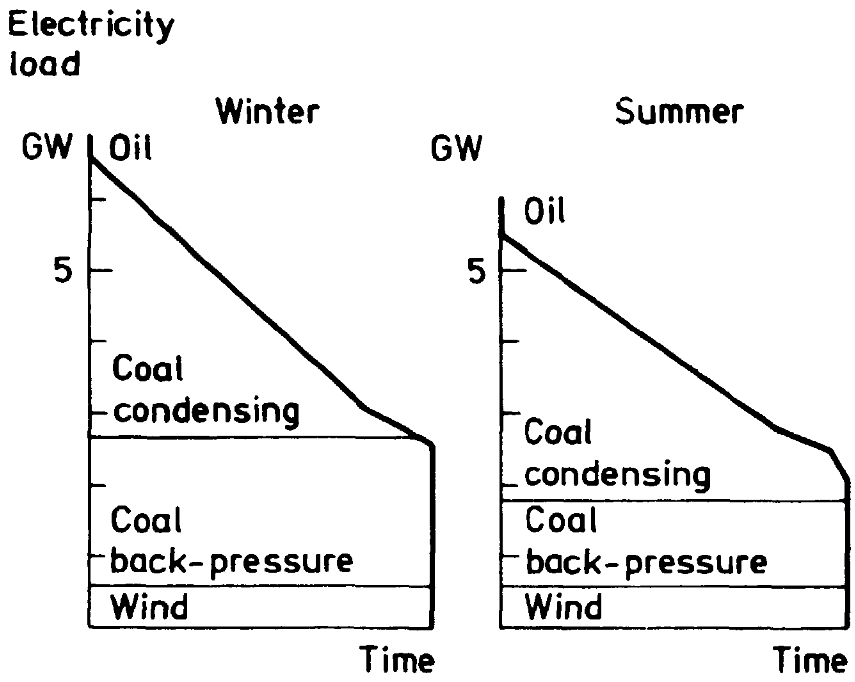

Fig. 4.5. Load duration curves and production structure for the Danish power system by 2010. (Total power demand 40 TWh)

For the simulation by both models electricity production from wind turbines may be considered as a negative demand, and the load curves and load duration curves are to be modified accordingly. This modification must reflect both the wind pattern and the capacity of wind turbines. In Fig. 4.5, however, wind power has been shown as a constant for simplicity.

4.3.2. Electricity imports and exports

There are strong connections between the electrical networks of Denmark and its neighbours. The transfer capacity to Norway and

Sweden is 1.5 GW and to Germany 1.0 GW, or some 20 to 30 per cent of the Danish maximum load. In 1983 the total Danish demand was 24 TWh, 10 TWh of which was net import of hydro and nuclear-generated electricity from Norway and Sweden, and 2 TWh was net export to Germany as a substitute for oil, gas or coal-generated electricity. This trade pattern, however, is very fluctuating; in the first half year of 1985 there has been a net export from Denmark due to small hydro power generation in Norway and Sweden.

More transfer capacity and a more advanced transmission technology in the future may increase this electricity trade. The price of the traded electricity must reflect the variable costs of the generation and the avoided costs of the displaced generation, i.e. higher than nuclear or coal-fired CHP, but lower than oil, gas or coal-fired generation.

In the simulation models electricity imports and exports may be treated by modification of the power demand - like wind power - and it must be specified exogeniously. It may, however, be included in the simulation, if an appropriate share of foreign power stations and foreign power demand is taken into account.

4.3.3. Power-generating units

Each model is able to simulate a generating system consisting of many different units. This is important for an accurate simulation of conditions in the near future, when the system structure is well known and units will be present of various sizes and efficiencies. For simulating conditions much further in the future when uncertainties prevail, a more simplified model of the system is preferred.

The thermal production of the future Danish power system can be simulated using identical technical data for units of the same type. The data used in the DES-Model are shown in Table 4.1; the "coal-fired" units are mixed fuel units using 5 per cent oil for start-up and low-level production; peak load is supplied by expensive production from oil-fired reserve capacity. The Simulachron model requires more detailed technical data.

All the units are interconnected by the transmission grid including an expected future connection across the Great Belt, and no limit of transfer capacity for the grid is assumed.

4.3.4. Heat regions

The structure of the demand for heat from CHP is described by three types of heat regions: the Copenhagen Region, five city regions (Odense, Aarhus, Aalborg, Esbjerg, and the Skaerbaek Region), and several smaller towns.

The Copenhagen and other city regions are supplied mainly by large extraction plants, 200-400 MW. There may, however, be some older and smaller CHP units in these heat regions. The power capacity of the extraction units that exceeds the need for heat demand is simulated like the condensing units.

In the future the smaller CHP towns will be supplied mainly by back-pressure units between 10 and 90 MW designed for the heat demands of the particular towns. The production at these units either follows the diurnal heat demand variations, or, there is a heat storage which allows the back-pressure unit to produce full load part of the day and be closed down for the rest of the time. Today, back-pressure units designed for the heat region are found in Herning and Randers, and some smaller towns are supplied with heat from nearby large power plants consisting of condensing units with minor extraction facilities.

When simulating the power system in the near future it is necessary to describe all major heat regions with planning data for each region. Scenarios for the more distant future may be based on simplified assumptions for the three types of heat regions.

Table 4.1. Technical and economic data for new power units

	Nuclear	Coal Condens-ing	Coal Extrac-tion	Coal Back-Pressure
Maximum power output, MW_e	900	600	350	10
Max. power at max. heat output, MW_e			272	10
Maximum heat output, MJ/s			435	20
Heat rate at condensing prod. MJ/kWh	10.7	8.7	8.7	
(efficiency η_p)	(0.336)	(0.413)	(0.413)	
Heat rate at back-pressure prod. MJ/kWh			4.33	4.33
(efficiency η_p^{CHP})[1]			(0.83)	(0.83)
Basic fuel TJ/a[2]	450	1200	700	20
c_m MW/MJ/s			0.63	0.50
Availability	0.70	0.85	0.85	0.85
Operation and maintenance costs[3]				
Labour hours per kW/per annum	2.70	0.80	0.90	5.00
Labour hours per MWh	0.02	0.10	0.13	0.50
Investment costs DKK-1984/MW	8900	4300	4500	7100
Distribution of capital costs during construction, per cent				
6 years before commissioning	12	2	2	0
5 " " "	18	8	8	5
4 " " "	20	20	20	5
3 " " "	24	35	35	20
2 " " "	14	25	25	40
1 " " "	12	10	10	30
Annual capital costs at 25 year life-time, per cent of investment costs				
5 per cent real interest	8.25	8.02	8.02	7.70
7 " " " "	10.59	10.17	10.17	9.61
9 " " " "	13.33	12.65	12.65	11.78

Source: Elsam (1984), Energiministeriet 1984b, and the author.

1) The compound efficiency of heat plus power, η_m, and the efficiency of coal-fired district heating boilers are both assumed to be 0.83

2) 7000 hours idle running

3) Labour costs 67 DKK-1984 per hour

4.4. Structural changes of the Danish power system

The effects of the structural changes of the Danish power system that are planned to take place before 2000 are illustrated in Table 4.2 as scenarios for the years 1985, 1990, and 2000 that are simulated using the DES-Model. The basic assumptions for these scenarios, which are in accordance with the Danish energy planning (Energiministeriet 1984a), are:

- increasing power demand,
- expansion of CHP areas and CHP supply units, and
- introduction of flue gas desulphurization (FGD).

The main results of the simulation which are shown in Table 4.2 are data for the thermal power production at the various generating units, in particular the power production at units with FGD and back-pressure mode production. The fuel requirements of coal and oil are calculated, taking into account a necessary use of oil for start-up at mainly coal-fired units. The amount of fuel that is assigned to power production may vary within certain limits depending on the treatment of the CHP-benefit.

The total emissions of SO_2 from power stations can be calculated. This is illustrated in Tabel 4.2 using the emission factors 0.72 and 1.17 kg per GJ coal and oil, respectively; these emission factors are reduced by 70 per cent at units with FGD, which are planned to be introduced in the late 80s (Miljøstyrelsen, 1984).

The development in power system costs is shown in Fig. 4.6.

Table 4.2. Scenarios for the Danish power system 1985, 1990, and 2000 by simulation using the DES-Model

	1985	1990	2000
Generating capacity, GW			
coal-fired with FGD	-	1.2	5.2
coal-fired without FGD	6.3	5.7	2.7
oil/gas-fired without FGD	1.7	1.0	1.0
Total	8.0	7.9	8.9
Heat supply by CHP, PJ			
Copenhagen region	13.9	24.9	32.8
Five city regions	22.9	28.8	30.7
Smaller towns	7.2	9.6	23.5
Total	44.0	63.3	87.0
Power production, TWh			
Total demand	26.3	29.8	35.8
Net imports	1.5	-	-
Supply from wind, etc.	0.2	0.5	3.2
Thermal production	24.6	29.3	32.6
of which:			
from coal-fired units	24.2	29.3	32.6
from units with FGD	-	8.2	27.0
back-pressure mode production	5.7	9.2	13.8
Fuel requirements, PJ			
Coal	248	296	326
Oil	9	11	14
Total	257	307	340
of which for power production:			
CHP benefit assigned to power	205	233	238
CHP benefit assigned to heat	236	278	301
SO_2 emissions from power stations, 1000 t	190	198	153

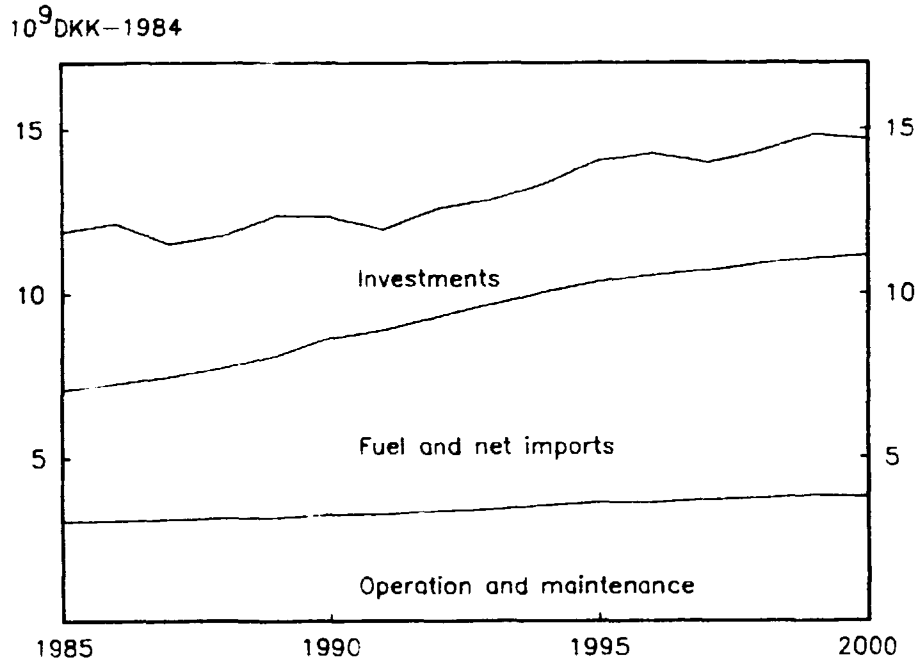

Fig. 4.6. Costs of the Danish power system 1985-2000

4.5. The structure of the Danish power system by 2010

By 2010 the Danish electricity generating system will consist of units for which planning decisions have been or will be taken between 1970 and 2000. Either a substantial part of these units already exists in 1985, or they are under construction or planning. However, some degree of freedom to decide about new capacity still exists.

4.5.1. DES-Model simulations

Table 4.3 shows some results of simulations by the DES-model for a low and a high electricity demand scenario and a number of feasible structures for the generating system by 2010, using the technical and economic data for new power stations shown in Table 4.1.

Table 4.3. DES-Model simulations of the Danish power system by 2010

Total electricity demand	25 TWh/a				40 TWh/a						
No. of nuclear units	0	1	2	3	0	1	2	3	4	5	6
Capacity of thermal units, MW											
Nuclear	-	900	1800	2700	-	900	1800	2700	3600	4500	5400
Coal-fired, extraction units	3150	3150	2800	2450	3150	3150	3150	3150	3150	3150	2800
Coal-fired, back-pressure units	400	400	150	100	400	400	400	400	400	400	150
Coal-fired, condensing units	2400	1500	1200	1200	6000	5100	4200	3300	2400	1500	1200
Total	5950	5950	5950	6450	9550	9550	9550	9550	9550	9550	9550
Production structure, TWh											
Wind	2.5	2.5	2.5	2.5	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Nuclear	-	5.5	11.0	15.5	-	5.5	11.0	16.5	21.5	25.5	28.6
Coal-fired back-pressure mode	13.8	11.8	8.2	5.1	14.5	14.1	12.9	10.8	8.5	6.4	4.4
Coal-fired condensing mode	8.7	5.2	3.3	1.9	21.5	16.4	12.0	8.6	6.0	4.1	3.0
Total	25.0	25.0	25.0	25.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Total costs 10^9 DKK-1984	8.81	8.44	8.16	8.40	15.19	14.58	14.08	13.72	13.53	13.51	13.51
Costs, 10^{-2} DKK/kWh											
Capital	12.5	14.8	16.6	19.7	12.5	13.9	15.3	16.8	18.2	19.6	20.8
Operation and maintenance	4.4	4.4	4.0	4.1	4.2	4.2	4.1	4.1	4.1	4.2	4.1
Fuel	22.3	18.3	15.6	13.5	25.5	22.4	19.6	17.3	15.3	13.7	12.7
Total	39.2	37.5	36.2	37.4	42.2	40.5	39.1	38.1	37.6	37.5	37.5

Fuel prices: Coal: 95 \$-1984 per ton (25.1 GJ/t, 9 DKK/\$) c.i.f. Danish harbour (1984: 42 \$/t)
Nuclear: 0.10 DKK/kWh calculated as levelized costs including back-end of the nuclear fuel cycle and dismantling of nuclear plants (0.02 DKK/kWh, see Energiministeriet 1984b p. 74).
Technical and economic data: see Table 4.1; interest rate 7 per cent p.a.

In the case of high electricity demand the capacity requirement is so large that six 900-MW nuclear units can be phased into the system instead of new coal-fired capacity. In the low-demand case no more than two nuclear units can be phased in. The heat demand in CHP-areas and the wind-generating capacity are the same in all scenarios; all large coal-fired units have FGD-facilities.

The electricity production is simulated under the assumption of no interaction with the international grid. According to the expected merit order, which is based on an assumption of a substantial increase in all fossil fuel prices, even compared to those of the early 80s, nuclear production will displace all other production except wind, which means that cogeneration is reduced and displaced by nuclear except in the case of a high demand and few nuclear units. However, the cost margin between nuclear and cogeneration is much smaller than the margin between nuclear and coal-fired condensing generation.

The coal price forecast is based on the assumption that coal from the eastern USA will obtain price leadership in the long run, so that the coal price in Denmark will depend on the production costs for these coal and freight rates (Energiministeriet 1984b pp. 37-41). Although also the uranium price is expected to increase in this period, neither the expected cash flow profile of the nuclear fuel cycle during the lifetime of the plant, nor the assumed uncertainties for the various cost components of the fuel cycle makes it necessary to include nuclear fuel cost variations in the present analysis (see OECD/NEA 1985 pp 65 and 76).

According to Table 4.3 the first two nuclear units will reduce total costs by about 5 per cent in both cases. Further nuclear units will increase total costs in the low demand case. In the high-demand case the total costs are lower in a system with 3-6 nuclear units, but the difference is very small. The difference in cost structure is more important than that in total costs, because of the uncertainties in the basic cost parameters. In the high-demand case with 6 nuclear units fuel costs are reduced by 50% compared with an all-fossil-fuel system, and therefore, this system is more robust against fuel price changes. It must be borne in mind, however, that as more nuclear units are introduced the simulation results become less reliable, because the impact of load variations is simulated in a very simplified way in the DES-Model.

4.5.2. Simulachron model simulations

Table 4.4 shows some results of similar simulations by the Simulachron model using the variations of electricity and heat loads shown in Fig. 4.4. Within each heat region the heat load dispatch between combined production and boilers takes into account the value of the co-produced electricity, which is equal to the marginal power cost. The electricity production in back-pressure mode is determined by the heat load dispatch; if this production is higher than the electricity demand at the time step, the surplus electricity is assumed being exported.

Then the electricity production is optimized for the whole 3-day period; and a new set of marginal power cost for each time step is produced, which may be used in an iterative process as described in Section 4.2.5.

In Table 4.4, showing the results of the first run of this iterative process, the marginal costs of coal-fired condensing mode production are chosen as marginal power costs. These costs are also used as the price for power exports. The simulations of the power system with nuclear units have shown that nuclear power production may be the marginal one in some situations, making combined heat production less competitive compared with boilers. In these cases a second and third run of the iterative process was tried. These runs show considerable changes in the load dispatch between nuclear and back-pressure mode coal-fired production, but only small reductions in fuel and operating costs. The costs of the optimal solution for the high demand case with 5 nuclear units in the winter week may be 5 per cent lower than

Table 4.4. Simulachron model simulation of the Danish power system by 2010

3-day period	Winter					Summer				
Total electricity demand	25 TWh/a		40 TWh/a			25 TW/a		40 TWh/a		
Number of nuclear units	0	2	0	2	5	0	2	0	2	5
Heat demand, GWh	250.2	250.2	250.2	250.2	250.2	140.6	140.6	140.6	140.6	140.6
Extraction units (c_m = 0.63)	213.3	207.3	213.3	213.3	213.3	119.9	119.9	119.9	119.9	119.9
Back-pressure units (c_m = 0.50)	36.9	13.8	36.9	36.9	36.9	20.7	7.8	20.7	20.7	20.7
Boilers	-	29.0	-	-	-	-	12.9	-	-	-
Electricity demand, GWh	190.8	190.8	305.3	305.3	305.3	179.0	179.0	286.5	286.5	286.5
Nuclear	-	53.0	-	110.5	151.5	-	92.1	-	125.6	199.9
Coal, back-pressure mode	152.8	137.5	152.8	152.8	152.8	85.9	79.4	85.9	85.9	85.9
Coal, condensing mode	40.8	0.9	152.5	42.0	0.9	93.2	7.6	200.6	75.0	0.6
Peak load units	0.0	-	-	0.0	-	0.0	-	-	0.0	-
Exports	2.8	0.7	-	-	-	-	-	-	-	-
Costs 10^6DKK-1984	83.8	75.6	123.4	98.8	91.3	72.5	53.3	110.2	82.0	67.3
Index (0 nuclear = 100)	100.0	90.2	100.0	80.1	74.0	100.0	73.4	100.0	74.4	61.1

the costs found by the first run. In the other examples the costs of the optimal solutions are unlikely to be more than 2 per cent lower than those found by the first run, which are shown in Table 4.4.

In Table 4.5 the results from the Simulachron simulation are compared with those from the DES-Model. For simplicity the annual production is made up of an equal number of winter and summer 3-day periods. This calculation, however, does not take into account forced and scheduled outages of units producing at low costs, leading to a production from nuclear units that is too high, especially in situations with few nuclear units. The consequenses of these outages might be taken into account by including a number of periods that are simulated with a reduced number of available units, or - as done in Table 4.5 - by using a weighted average of two simulation runs by Simulachron with different nuclear capacity in order to reach the assumed availability for the nuclear units.

4.6. Simulation accuracy

A comparison of simulation results by the DES-Model for the years 1980 to 1983 with recorded fuel consumption for the Danish power system shows that the model calculations done so far has underestimated the fuel requirement by some five per cent. This difference can easily be overcome by introducing an appropriate correction factor. The difference, however, indicates that the efficiency parameters (i.e. heat rates and fuel requirements for start ups) may be too optimistic; or that the load duration curve, which is made up of the demand load variation, does not take into account that there has been a substantial foreign trade with electricity.

The efficiency parameters and the load duration curve have been kept constant at traditional values for reasons of comprehensiveness. Introducing a new set of parameters into the DES-Model that gives more accurate results will require a thorough study

Table 4.5. Comparison of DES and Simulachron model simulations

Total electricity demand	25 TWh/a		40 TWh/a		
Number of nuclear units	0	2	0	2	5
Capacity of power units, MW					
Nuclear	-	1800	-	1800	4500
Coal, extraction units	3150	2800	3150	3150	3150
Coal, back-pressure units	400	150	400	400	400
Coal, condensing units	2400	1200	6000	4200	1500
Total	5950	5950	9550	9550	9550
Heat demand, PJ	85.6	85.6	85.6	85.6	85.6
DES model, simulation, TWh					
Nuclear	-	11.0	-	11.1	25.5
Coal, back-pressure mode	13.8	8.2	14.5	12.9	6.4
Coal, condensing mode	8.7	3.3	21.5	12.0	4.1
Peak load units	-	-	-	-	-
Demand 1)	22.5	22.5	36.0	36.0	36.0
Fuel and operating costs 2), 10^9 DKK-1984	9.4	7.8	14.1	12.0	9.9
Simulachron model simulation 3), TWh					
Nuclear	-	7.8	-	10.5	26.0
Coal, back-pressure mode	14.5	13.2	14.5	14.5	3.1
Coal, condensing mode	8.1	1.5	21.5	11.0	6.9
Peak load units	0.0	-	-	0.0	-
Total production	22.7	22.5	36.0	36.0	36.0
Exports	0.2	0.0	-	-	-
Demand	22.5	22.5	36.0	36.0	36.0
Fuel and operating costs, 10^9 DKK-1984	9.5	8.1	14.2	11.9	9.7

1) Total demand minus production from wind turbines.
2) Including fuel costs for the heat demand, 3.4 x 10^9 DKK.
3) Calculated from Table 4.4 by adding the figures for winter and summer and multiplying by 60.83. In the cases with 2 nuclear units, however, a weighted average is used of simulations with 1 and 2 nuclear units, not to exceed the availability of the nuclear units, which is set at 0.70.

of the power system and its model representation. This might be done by comparative studies of the system by the DES-Model and the Simulachron model.

5. THE ENERGY SYSTEM OUTSIDE THE POWER PLANTS

The simulation of the energy system outside the power plants is based on the annual demands for the various kinds of useful energy, and does not take into account the seasonal and diurnal demand variations. The existing DES-Model does not include the off-shore oil and gas sector and the refineries. Apart from these sectors the simulation includes those elements of the energy system that are of interest for national planning purposes, because they require large capital investments or involve planning decisions by central or local authorities. The most important of these elements are the electricity, natural gas, and district heating networks, all renewable energy systems, and all heating installations.

5.1. Energy conversion units

As the Danish natural gas system now is being completed as planned, according to decisions made earlier, the most important energy conversion units for the future energy planning outside the power system are renewable energy installations and other heat installations (see Table 5.1).

Renewable energy installations produce mainly electricity and heat for space heating. Straw furnaces and biogas plants may also produce heat for e.g. grain-drying or heating of agricultural production buildings, which is considered as process energy. In the DES-Model the output from renewables will reduce the demand for other energy supply.

Although wind turbines and sun panels do not use fuel, the model calculates the amount of displaced fuel that is included in the total energy requirement as "renewable energy". Biomass used in biogas plants is treated in the same way, while straw is considered as a real physical fuel.

Table 5.1. Selected conversion units

	Energy input	Energy output	Size (capacity)	Efficiency	Annual elec. MWh	Production useful heat GJ	Investment 10^3 DKK	O&M 10^3 DKK/a
Renewables								
Wind turbine	(Wind)	Electricity	55 kWe				450	6
Biogas plant	(Biomass)	Elec. + heat	150 m^3gas/day		87	315	560	42
Electric heat pump	Electricity	Piped heat	15 kW	2.20			45	1
Sun panel	(Sun)	Piped heat	6 m^2				23	0
Small straw furnace	Straw	Piped heat		0.60		115	84	1
Large straw furnace	Straw	District heat	5 MW_{th}	0.82			6300	410
Other heat installations								
Direct electric heat	Electricity	Room heat	SFD	1.00			19	0
Other electric heat	Electricity	(Piped heat)	SFD	1.00			71	1
Gas furnace	Natural gas	Piped heat	SFD	0.80			15	1
Oil furnace	Gas oil	Piped heat	SFD	0.75			40	1
House installation	District heat	Piped heat	SFD	1.00			14	0
Heating plant	Coal	District heat	5 MW_{th}	0.80			4500	340
			10 MW_{th}	0.80			9100	560
Heating plants	Oil	District heat	per MW_{th}	0.88			...	...

SFD: Single family dwelling

Electrically driven heat pumps also displace fuel, although this amount may be smaller than the primary fuel requirement for the electricity. For simplicity, the contribution from heat pumps to "renewable energy" therefore is set at zero. It must be observed that the number of heat pumps will have an effect on the total demand for electricity, however.

Other heat installations include electrical heating systems, oil and gas furnaces, and house installations for district heating, as well as fossil-fueled district heating plants.

5.2. Energy transmission and distribution

The transmission and distribution grids for electricity, district heating and natural gas are included in the model only by an efficiency rate, and by the planned investment and operating costs. The efficiencies used in the model are 0.90 for the electricity grid, 0.80 for the district heating grids, and 0.97 for the natural gas grid including the treatment plant for raw gas.

5.3. The space heating system

The simplest space heating system consists of a stove in a room where primary energy, delivered to the house, is burned directly to provide useful energy, the loss being quantified by the heating efficiency. In a central heating system two stages and two efficiencies are specified: the furnace which produces hot water and the radiator system which distributes the hot water to the rooms. More stages are introduced in systems of piped energy, such as natural gas, district heating, or electrical heating. The structure of the various heating systems is shown in Fig. 5.1, which is a close-up of the heating system in Fig. 2.2.

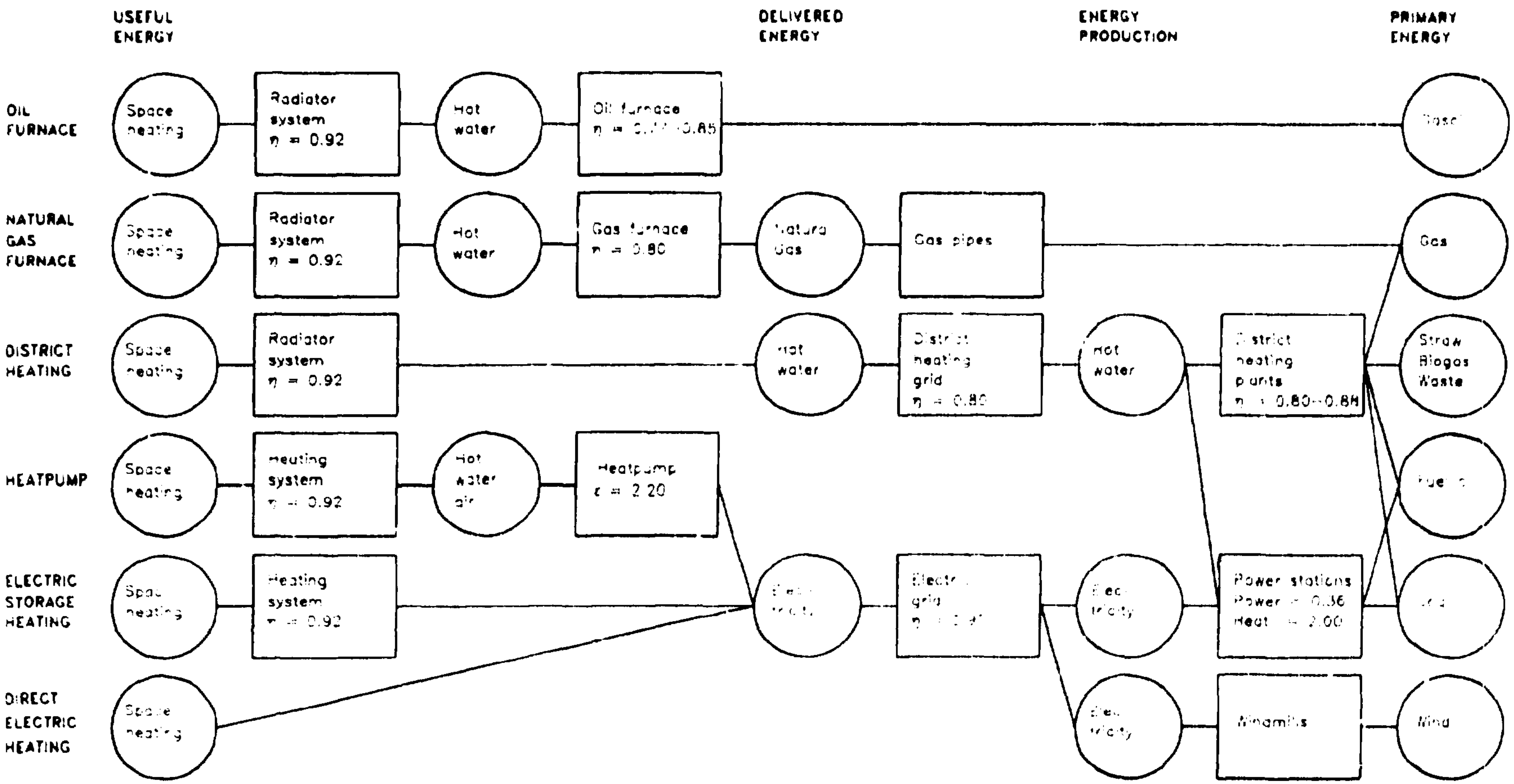

Fig. 5.1. The space heating system

Some of the stages of the heating system are used for analysis on a national or regional level as a part of the DES-Model. These stages are:

- Useful Energy: energy for space heating and domestic hot water, measured at the radiator or the hot water tap, i.e. all kinds of losses in the conversion and distribution systems are omitted.

- Delivered Energy: energy delivered to the final consumer, e.g. gas-oil delivered to the building where it is consumed, or piped energy measured by the meter at the entrance to the building.

- Energy Production: energy produced in a conversion plant which is sent into the transmission grid.

- Primary Energy: energy consumed by a conversion plant, or non-piped energy delivered to the consumer.

The space heating system includes the demand for useful energy in all buildings except those for industrial and agricultural production. The demand is calculated as the product of building areas and useful energy demand per m^2 in buildings of various kinds and uses.

Table 5.2, which shows a simplified mapping of the Danish space-heating system, is derived from a run of the DES-Model. These amounts of useful energy, delivered energy and primary energy are distributed among the various heating forms, and the total building area is distributed accordingly. The exogenenous variables are: total useful energy demand, energy production from CHP and waste incineration, natural gas delivery, and a few other variables such as the number of installations for renewable energy or electrical heating. The values of the efficiencies are assumed, and the remaining variables are calculated.

Table 5.2. The space heating system 1983 and 2000

	Building areas mill. m^2	η total	Useful energy PJ	η radiat. system	η furnace	Delivered energy PJ	η grid	Energy product. PJ	η plant	Primary energy PJ
1983										
Electrical heat, direct	12	(0.32)	6 1)							
storage etc.	2	(0.30)	1 1)	0.92		4	0.90	5	0.358	14
heat pumps	2	0.65	1	0.92	2.20					
District heat, CHP	45	1.47	23					32	2.00	16
waste incenerat.	10	0.63	5					7	0.85 4)	8
straw	2	0.60	1	0.92		69	0.80	1	0.82	1
natural gas	2	0.65	1					1	0.88	1
coal	10	0.59	5					7	0.80	8
fuel oil	55	0.65	28					39	0.88	44
Heating centrals, fuel oil	12	0.77	6	0.95	0.81	8				8
Individual, gas furnace	6	0.61	3	0.92	0.66 3)	5				5
renewables	8		4	0.92	2)	7				7
oil furnace	150	0.70	76	0.92	0.76	109				109
Total	316	0.72	160			202				221
2000										
Electrical heat, direct	7	(0.36)	3 1)							
storage etc.	18	(0.33)	8 1)	0.92		10	0.90		0.395	29
heat pumps	13	0.72	6	0.92	2.20					
District heat, CHP	124	1.47	56					76	2.00	38
waste incenerat.	18	0.63	8					11	0.85 4)	13
straw	9	0.60	4	0.92		9	0.80	5	0.82	6
natural gas	24	0.65	11					15	0.88	17
coal	13	0.59	6					9	0.80	10
fuel oil	7	0.65	3					4	0.88	4
Heating centrals, fuel oil	4	0.77	2	0.95	0.85	2				2
Individual, gas furnace	69	0.84	31	0.92	0.92	37				37
renewables	13		6	0.92	2)	11				11
oil furnace	53	0.78	24	0.92	0.85	31				31
Total	372	0.85	168			186				198

1) Average demand, the actual electricity demand is lower
2) Straw furnaces 0.60, others displaced gas oil
3) Including gas-works
4) Displaced fuel oil

The efficiencies of plants and grids may be estimated from historical data for primary energy, energy production (i.e output from power stations and district heating plants), and delivered energy to the final consumers. These data are obtained from various statistical sources. The data on useful energy and local efficiencies depend on the performance of the individual buildings, which is not found in the statistics. The assumptions were based on a number of investigations of the energy performance of buildings.

In the model calculations the supplies of district heating from CHP, natural gas, waste incineration and renewables are known from the electricity sector of the model, or provided exogenously. Necessary peak load is provided by oil, and the rest of the supply for district heating is covered by coal or oil. For single-family houses the numbers of installations for district heating, electrical heating, natural gas, and renewables are given as forecasts. The rest of the houses are heated by oil furnaces fired by gas oil. Other buildings that are not connected to the district heating grid are heated either by fuel-oil or by gas oil.

5.4. Energy conservation and heat planning

A reduction of the primary energy requirement for heating, and thus the fuel costs, may be obtained by:

- reducing the demand for useful energy
- increasing heating efficiencies of the existing system, and
- changing the structure of the heating system in favour of more efficient systems.

The demand for useful energy is reduced by better insulated houses and behavioural changes by the consumer. Increased heatting efficiencies are obtained by, e.g. installation of more efficient oil furnaces, renewal of district heating grids, and by more efficient district heating plants or power stations. An increase of the total efficiency of the heating system is obtained by the introduction of renewable energy systems, and increased use of CHP, district heating supplied by waste incineration, and industrial excess heat. In addition, fuel costs may be reduced by the substitution of coal or natural gas for oil.

The Danish Act on Heat Supply, which was passed in 1979, regulates the operation of collective heat supply systems, i.e. district heating and natural gas systems, and contains a procedure for heat planning, which is an extention of the physical planning system that was developed during the 70s. The main features of the heat planning has been the introduction of natural gas, expansion of district heating systems, and zoning of areas most suitable for natural gas, district heating, or individual heating according to criteria such as proximity to natural gas mains or power plants, building density, and the existence of a district heating grid.

The Danish natural gas is produced in the North Sea some hundred kilometres from the coast, and the introduction of natural gas to the Danish consumers has required a large threshold investment, which has called for a rapid penetration of all available market segments.

District heating, on the other hand has a long tradition, and the existing structure has developed through local initiative. CHP-systems producing steam or hot water for district heating have existed in the large cities for more than 50 years. These systems were expanded in the 50s and 60s, and a great number of new district heating systems were established in medium-size and small towns. Today there are more than 400 district heating companies - owned by municipalities or co-operative bodies.

As a result of this development in the past, the share of buildings in the densly populated Copenhagen Region supplied by district heating is remarkably low, compared with the larger cities and towns, and even with small towns in rural regions. Thus, there is still a large potential for increasing the CHP-coverage: by the expansion of the district heating grid in the Copenhagen Region, which can be connected to large power stations; and by the construction of small back-pressure units in towns with existing grids that are supplied by district heating plants fired by fossil fuels.

5.5. Process and transport energy systems

Process energy in the DES-Model includes the demand for fuels, electricity, and district heating in industry, agriculture and forestry, horticulture, fishery, and construction. The definition of process energy includes internal transport and heating of production buildings. Forecasts of process energy demand are made by econometric methods for four types of fuels: solid, fluid, electricity, and transport fuels. No general useful energy concept can be derived for process energy. The only calculations that are made within the DES-Model for process energy other than electricity are the substitution of natural gas, district heating, and renewables for solid and fluid fuels as well as splitting fluid fuels into oil products according to some aggregate parameters.

Like process energy demand no useful energy concept is defined for transport energy, so the transport energy demand is described by the demands for transport fuels and electricity. The transport energy demand is divided into the subsectors: persons, goods, and other transport, the latter including foreign air traffic and defence. The energy demands for agriculture, fishery, and internal transport are included in the process energy demand; and foreign bunkering is not included in the national energy demand.

ˉ. PRIMARY ENERGY DEMAND AND ENERGY SYSTEM COSTS

Having described the components and structure of the energy system, the primary energy demand and the costs of the energy system may be calculated assuming forecasts for useful energy demand and fuel prices.

6.1. Energy demand forecasts

Forecasts for the useful energy demand - or some indicator or substitute for that - are assumed for the four energy demand sectors:

- process
- transport
- space heating, and
- non-substitutable electricity

covering the whole energy system to be included in the scenario.

The economic development is given by extrapolations of medium-term forecasts using the macro-economic model ADAM (Annual Danish Aggregate Model), which is used for evaluation of the economic policy of the government and run by the Ministry of Finance. The assumptions on the development in the number of households are based on demographic forecast carried out by the Danish Statistical Office.

6.1.1. Process energy demand

Process energy in the DES-Model includes the demand for fuels, electricity and district heating in industry, agriculture and forestry, horticulture, fishery, and construction. The definition of process energy includes internal transport and heating of production buildings.

For the Energy Plan 81 and the Energy Reviews that followed, the forecasts of process energy demand were based on the expected development of gross output and energy coefficients in the six industrial branches in the ADAM model and forecasts of the development of the energy demand in the other sectors. Very simplified energy coefficients have been estimated by econometric methods for four types of fuels: solid, fluid, electricity, and transport fuels.

In order to improve the methods for forecasting this very important energy demend sector, a technical-economic model for energy consumption by industry has been developed by Risø for the Ministry of Energy for use as a forecasting tool in energy planning. Work on the model was started in January 1984 and the first forecasts using the model were obtained by the end of 1985.

The general structure of the model is shown in Fig. 6.1. At the top is found the macro-economic model ADAM. As the six industrial branches of this model are very heterogenous concerning energy, a simple split-model is used to divide the six branches into 14 more energy-homogenous branches. For each of the six branches the more energy-intensive subbranches are separated. Finally, an energy model converts the forecasts for economic growth and energy price development into those for the energy consumption by each of the 14 branches and the four fuels.

In order to build the model, the development since 1966 was analysed, and, to explain the development for each of the branches and fuels, both technical and economic factors were considered. The most important economic factors are changes in the level of production, real energy prices, employment, and investment. Two important technical changes that ought to be mentioned are the introduction of new production techniques or processes, and the starting up or closing down of specific production inside the individual branches. As most of these technical changes alter the level of energy consumption by one stroke they are represented in the model by dummy-variables, i.e. the historical

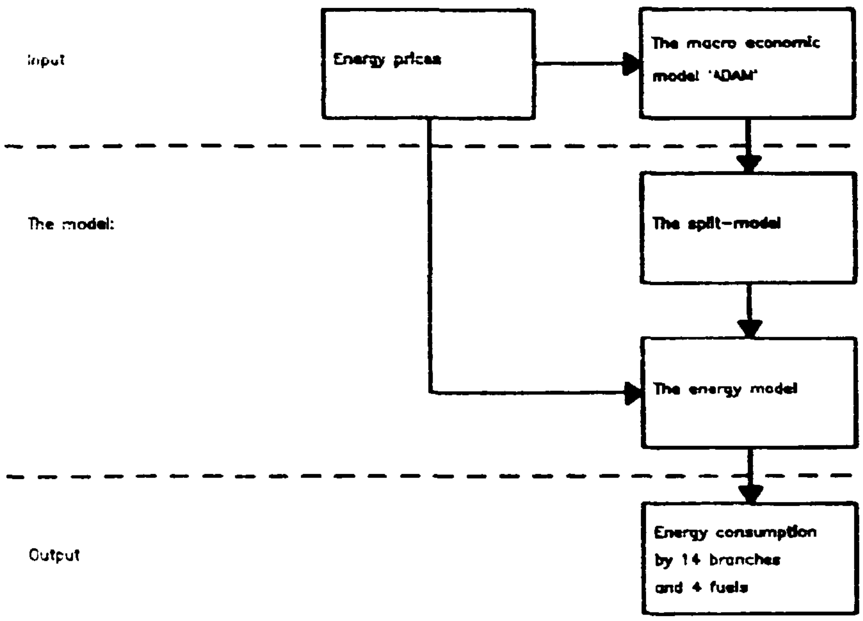

Fig. 6.1. The structure of the model for industrial consumption

development is corrected for one-time changes by 0-1 variables. What is obtained by this is that historical one-time changes are not implicitly reproduced in the forecasts, and that future one-time changes have to be considered explicitly.

The main conclusions from the historical analysis are that substantial differences exist between the branches, and that a major part of the energy savings are obtained by structural changes and by closing down some of the more energy-intensive productions inside the individual branches.

The model contains about 60 estimated equations plus a number of identities. The equations for the various branches are very different concerning the approach preferred, the variables included, and the nummerical size of the coefficients and elasticities. For the industry as a total, the model gives a production elasticity averaging about 0.7 and an energy price elasticity of about -0.3.

Using production and energy price forecasts from the Ministry of Finance, the forecasts of the model are given in Fig. 6.2. It shows that the energy consumption is expected to grow faster up till 1990 than after that year. The main reason for this is that up till 1990 some of the more energy-intensive branches are expected to recover and thus grow faster than the average for the industry (e.g. building materials).

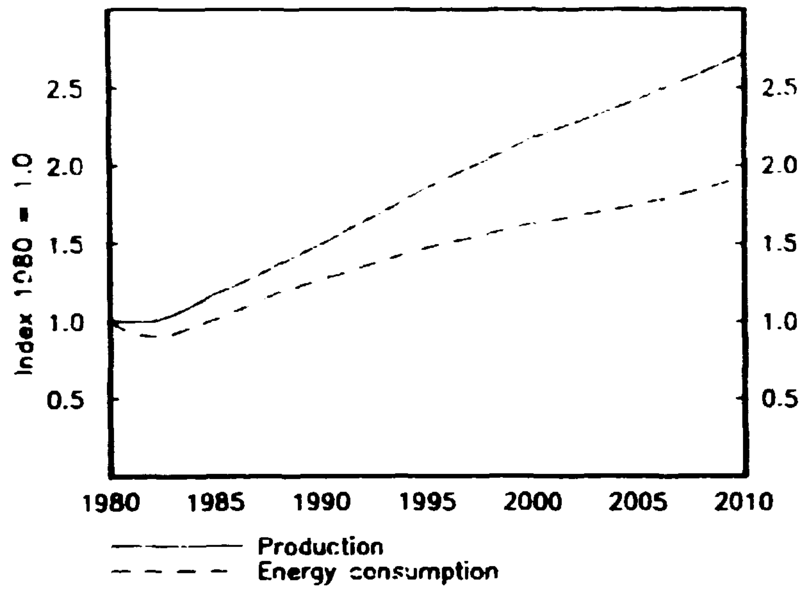

Fig. 6.2. Forecasts for industrial production and energy consumption.

6.1.2. Transport energy demand

Forecasts on transport energy demand has been based on surveys outside the energy sector. These surveys have partly been based on model studies that are designed for traffic planning rather than energy demand forecasting.

6.1.3. Space heating demand

The space heating sector includes the demand for space heating and domestic hot water in all buildings except those for industrial and agricultural production; the heat demand for the latter is included in process energy.

The demand is calculated as the product of building areas and useful energy demand per m^2. Forecasts are made for single and multi-family houses, commercial buildings, hospitals etc. built before and after 1980. The data on building areas by kinds and uses are supplied from the central Building and Dwelling Register (bygnings- og boligregistret, BBR). The future building areas are found by reducing the existing building stock by projected demolishings, and forecasts of new building areas are based on assumptions on economic growth and demographic development in the planning period.

In principle, the forecast for useful energy demand per m^2 should not take into account differencies between the various heating forms. However, the useful energy demand in houses with direct electric heating is systematically lower than that of other heating forms, because these houses are normally better insulated, and direct electrical heating allows a much better adjustment to comfort needs than other heating forms.

The assumed heat demands per m^2 floor area in buildings of various kinds and uses are shown in Table 6.1.

Table 6.1. Useful energy demand for space heating and domestic hot water per m^2 building area, 1985 and 2000

	Buildings constructed			
	before 1980		after 1980	
	GJ/m^2			
Single-family dwellings 1)	0.50	0.48	0.38	0.36
Multi-family dwellings	0.52	0.49	0.39	0.37
Commercial and service	0.54	0.51	0.41	0.39
Misc. production	0.32	0.31	0.26	0.25
Hospitals, etc.	0.72	0.67	0.60	0.58
Summerhouses, etc.	0.13	0.11	0.10	0.09

1) The heat demand in electrically heated houses is much lower than this average. The electricity demand for heating in a single family dwelling is set at 10,500 kWh in 1985 and 10,000 kWh in 2000, corresponding to 0.28 GJ/m^2.

6.1.4. Non-substitutable electricity demand

The so-called non-substitutable electricity demand consists of the demand for electricity which is not included in the three other demand sectors, mainly lighting and appliancies in the household and the commercial and service sectors, covering nearly 60 per cent of the total electricity demand in Denmark in 1984, which was 23.6 TWh.

During the 70s there was a rapid growth in the Danish electricity consumption, followed by stagnation from 1979 to 1984. The split between the main categories of consumers is shown in Fig. 6.3. The shares of the total electricity consumption decreased for the domestic and agriculture sectors, while the commercial and industrial sectors increased their shares from 1978 to 1984. However, the shares of the various sectors have fluctuated much during that period.

It is expected that these tendencies will continue in the future. Industry and perhaps the commercial sector will exhibit

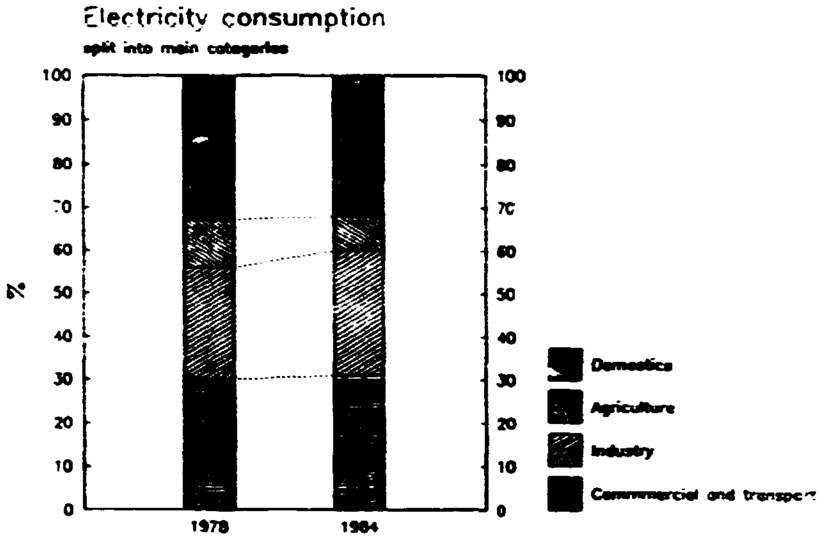

Fig. 6.3. Electricity consumption split into main categories, per cent.

the highest growth rates, while the domestic sector in particular will grow more slowly or stagnate.

For these reasons the electricity demand forecasting is based on a sectoral approach, and different methods are used for the various sectors.

The Danish households used about 7.6 TWh in 1984 or a little less than one third of total electricity consumption. This electricity consumption can be split into three main areas of use:

- appliances
- lighting
- electrical heating

Electrical heating is not very dominant in Denmark as only about 4-5 per cent is used for heating in households each year. About 80 per cent of electricity consumption in households is used for appliances and about 15 per cent goes to lighting. For that reason most of the work done in this sector is devoted to forecasting consumption for appliances, which is treated in detail in a vintage-stock forecasting model.

For each appliance the most important parameters in the simulation model includes:

- stock and purchase data
- frequency of use
- electricity consumption per usage

The stock of the various types of appliances is found using an S-shaped penetration curve, showing an introductory phase, a penetration phase, and a saturation phase. During the penetration phase the model takes into account an economic growth parameter, which is significant for some types of appliances. The scrapping of each type of appliance follows a normal distribution, for which the mean and standard deviation of the lifetime are estimated from stock and purchase data. The frequency of use of each appliance is obtained from regular consumer surveys carried out by the Danish Statistical Office.

For each vintage of appliance an average specific consumption is calculated, when possible, using measured electricity consumption data and its market share.

The commercial and service sector consumes a little less than one third of the total electricity consumption in Denmark, or 6.5 TWh in 1984.

In the commercial sector the consumption of electricity is heavily related to retail trade, especially shops selling everyday commodities and food. For the last-mentioned group more than 50 per cent of total shopping area is covered by the survey. The key data are annual electricity consumption in physical terms and the related shopping areas, taking special electricity-using equipment into account. The statistical data are mostly collected from large shop chains.

The public service sector is described by collecting data from municipalities, counties, large institutions and offices. The data are split into categories depending upon the function of the building: schools, hospitals, kindergartens, etc.

6.2. Fuel price forecasts

Based on the energy demand forecasts the future annual fuel requirements of the energy system are calculated using the DES-model for the following fuels

- coal
- fuel oil
- gas oil
- petrol/LPG
- natural gas
- straw
- nuclear fuel
- imported electricity

The fuel prices are used in the simulation of the power system for the merit order ranking of the generating units, which - together with the load duration curve - determines the load dispatch among the various power generating units. In all other parts of the DES-Model the fuel prices are used only for calculating the fuel costs. The fuel price forecasts, however, will influence the energy demand forecasts and may be significant for the choice of technologies and, hence, the development plans for the various energy supply sectors, which are exogenous to the DES-Model.

The fuel price forecasts for coal and oil products are made currently by working groups set up by the Ministry of Energy. The aim of these energy price forecasts is to indicate an interval within which price development will most probably occur.

The price of crude oil has been used to express the energy price level. In accordance with the terminology used by the International Energy Agency, this is to be understood as a weighted average of the prices of the most important types of crude oil traded in global markets.

Prices of other types of energy are influenced by the crude oil price, and, conversely, they influence the crude oil price as well, but crude oil is so dominant that it is natural to perceive the crude oil market as the place where the overall energy price formation occurs.

In the long term, however, the crude oil price is expected to rise relative to the price of coal. This is because resource problems will gradually lead to price increases for oil due to shortages, while ample deposits of coal, which can be extracted at relatively low prices, will have a curbing effect on coal price increases (Ministry of Energy 1983).

The crude oil price is not used directly in the DES-model, as the refinery sector is not included in the model. The forecast for coal and oil products are given c.i.f. Danish harbour. These fuel prices can be used directly for electricity production as all major Danish power stations are situated at deep water harbours. For all other uses distribution costs are added to the c.i.f. prices for coal, fuel oil, gas oil, and petrol, as the fuel distribution system is not included in the DES-model.

The whole transmission and distribution system for natural gas, which has been built up since 1979, is described in the DES-Model. For that reason the natural gas price is given ex platform in the Danish sector of the North Sea. A part of the Danish natural gas production is exported to Sweden and Germany; therefore, also a forecast of natural gas export prices is made.

In the latest version of the DES-model, straw is considered as a fuel, which has a price delivered at the consumer's gate.

The prices of imported and exported electricity have not yet been included in the forecasts, as no forecast has been made for the trade; the future trade, therefore, is set at zero.

6.3. Primary energy requirements

The primary energy requirements are calculated for each of the energy production sectors, and thereafter redistributed into the demand sectors.

Table 6.2 shows the annual electricity and heat production and the primary energy requirements in the electricity and heating sectors. The power system must supply the total domestic electricity demand as well as contracted exports due to foreign-owned generating capacity. The main part of the electricity is produced at thermal power stations. Renewables, i.e. mainly wind turbines, are planned to supply up to 10 percent, and some electricity may be imported. From the total fuel consumption of the power station an amount is subtracted that is assigned to heat production by CHP. In this case the efficiency of this heat production is set at 2.0-2.2, which means that all CHP-benefit is assigned to heat.

The heat producing sector covers the heat demand in buildings except industrial and agricultural production buildings. However, all district heating is included, and electrical heating is excluded.

The result of the redistribution of the primary energy demand into demand sectors is shown in Table 6.3.

Table 6.2. Production and primary fuel requirement in the electricity and heating sectors

	1983	2000
Electricity sector, demand, TWh		
Domestic demand	24.6	35.8
Contracted exports	1.5	1.5
Total	26.1	37.4
Electricity sector, supply, TWh		
Thermal power plants	20.3	34.2
Renewables (mainly wind turbines)	0.1	3.2
Net imports	5.7	0.0
Total	26.1	37.4
Electricity sector, fuel requirements, PJ		
Coal	176.1	284.2
Fuel oil	5.7	11.8
Diesel oil	0.0	0.0
Natural gas	0.0	0.0
Imports (fossil fuel equivalent)	57.8	0.0
Renewables (fossil fuel equivalent)	0.7	29.1
Total	240.3	325.1
Heating sector, production, PJ		
Useful energy demand	159.9	168.1
of which: Electrical heating	7.5	17.3
Useful energy demand minus elec. heating	152.4	150.8
of which: District heating	73.9	103.5
Heating sector, fuel requirements, PJ		
Coal for CHP	17.9	41.8
Fuel oil for CHP	0.6	1.7
Coal for district heating	8.4	10.7
Fueloil for district heating and heating centrals	51.8	6.4
Gasoil	108.8	31.0
Gas	6.3	53.3
Renewables	15.7	29.9
Total	209.5	174.8

Table 6.3. Primary fuel requirements at demand sectors, PJ

		1983	2000
Non-substitutable electricity	Total	146.3	148.5
Coal		107.2	129.8
Fuel oil		3.5	5.4
Gas/Diesel oil		0.0	0.6
Natural gas		0.0	0.0
Net electricity imports		35.2	0.0
Renewables		0.4	13.3
Space heating and domestic hot water	Total	220.2	197.9
Coal		33.6	72.1
Fuel oil		52.6	8.9
Gas/Diesel oil		108.9	31.0
Natural gas		6.3	53.3
Net electricity imports		3.2	0.0
Renewables		15.8	32.5
Process	Total	184.8	306.5
Coal		70.7	159.6
Fuel oil		48.8	54.2
Gas/Diesel oil		34.8	38.9
Natural gas		1.0	23.8
Petrol		6.0	10.0
Net electricity imports		19.0	0.0
Renewables		4.5	20.0
Transport	Total	139.4	156.2
Coal		1.1	5.4
Fuel oil		1.9	2.2
Gas/Diesel oil		45.7	52.9
Natural gas		0.0	0.0
Petrol		90.3	95.1
Net electricity imports		0.4	0.0
Renewables		0.0	0.6
All sectors	Total	691.3	810.3
Coal		212.6	366.9
Fuel oil		106.7	70.8
Gas/Diesel oil		189.3	122.9
Natural gas (incl. losses, etc.)		7.8	78.4
Petrol		96.3	105.1
Net electricity imports		57.8	0.0
Renewables		20.7	66.3

6.4. Energy system costs

Table 6.4 shows the annual running costs of the energy system for fuel and operation and maintenance in 1983 and 2000. The fuel costs are calculated at the consumer (or at the power station) as described in Section 6.2 and divided into fuel types and demand sectors. While the fuel costs are complete, the operation and maintenance costs cover only those parts of the energy system which are of interest for the energy planning and, therefore, included in the DES-Model.

The investment costs are shown in Fig. 6.4 for those types of energy investments that are dealt with in the energy planning, and the total annual costs are shown in Fig. 6.5.

Table 6.4. Annual fuel costs and operation and maintenance costs. 1983 and 2000, 10^9 DKK

		1983	2000
Fuel costs			
Coal		3.8	11.0
Fuel oil		4.0	5.8
Gas/Liesel oil		12.6	12.9
Petrol		7.3	11.8
Natural gas		0.3	3.0
Net electricity imports		0.6	0.0
Others		0.0	0.2
Minus: net revenue of gas exports		-0.0	-0.3
	Total	28.6	44.4
Non-substitutable electricity		2.4	4.2
Space heating and domestic hot water		10.1	8.3
Process		6.1	15.5
Transport		10.0	16.7
Losses of natural gas		0.0	0.1
Operation and maintenance costs			
Power stations		1.4	1.5
Electric grid		1.5	2.3
District heating grid		0.5	0.8
Natural gas grid		0.2	0.7
Heating installations		1.1	1.5
	Total	4.7	6.7

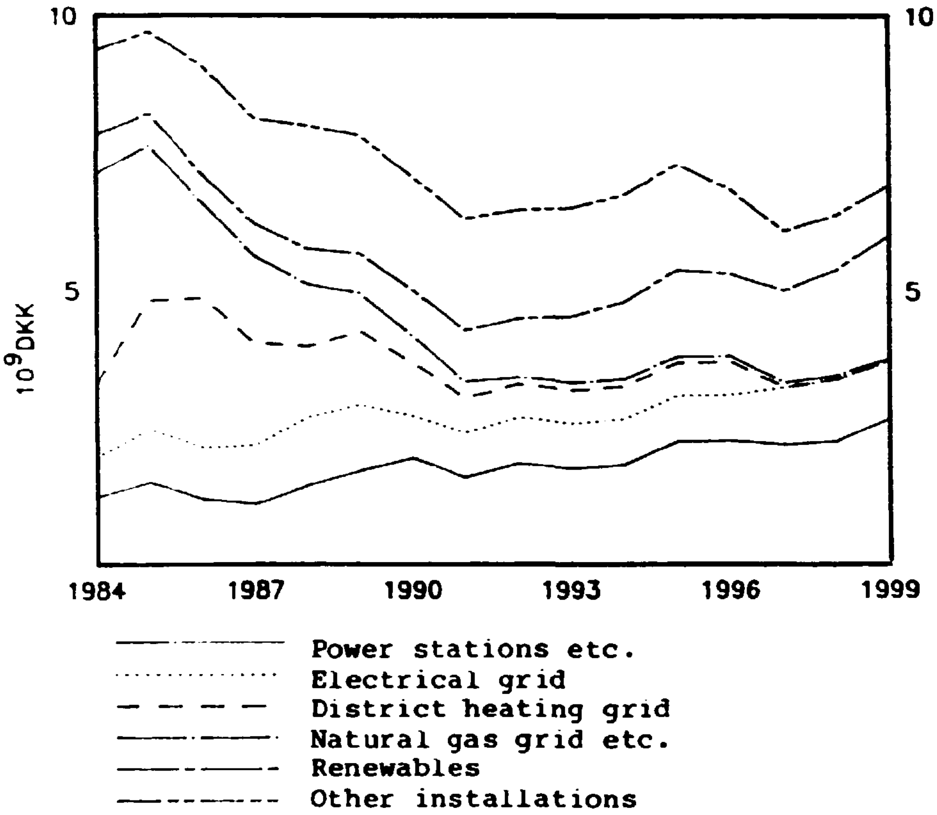

Fig. 6.4. Energy investment expenditures 1984-1999.

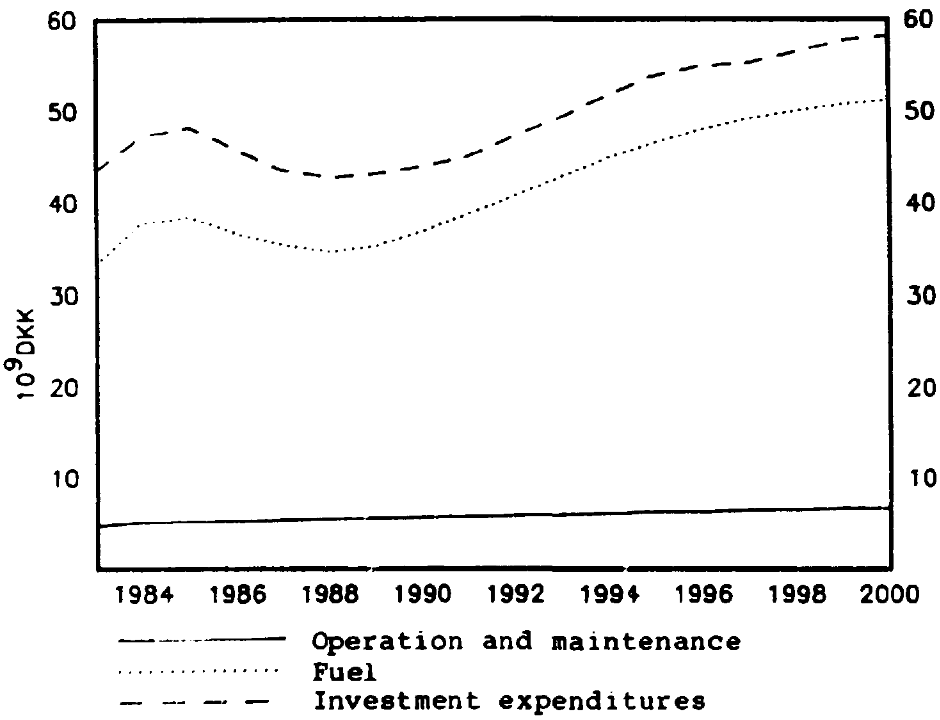

Fig. 6.5. Energy system costs

7. ENVIRONMENTAL CONSEQUENCES

Emissions of pollutants from energy production and energy consumption can be calculated from the primary energy demand disaggregated into appropriate sectors using emission factors, i.e. kg of pollutant per GJ fuel.

These calculations may be integrated into the various parts of the DES-Model, as described in Chapter 4 for the power system, or the calculations may be done in a subsequent module following the calculation of the primary energy requirements. An example of the latter is described in this chapter.

7.1. Emission module

This module was developed as part of a project, "Effects of Energy Changes on the Emissions of SO_2 and NO_x", which was initiated by the National Agency of Environmental Protection in order to study the cost-effectiveness of reducing the emissions of SO_2 and NO_x by measures such as energy conservation, increased efficiencies, and energy production with reduced environmental consequences (Grohnheit 1984).

The energy system is divided into the following sectors representing various types of emission sites

- Power stations
- District heating plants
- Process energy
- Collective renewable installation
- Individual renewable installations
- Individual furnaces
- Transport

In this context the primary fuel must be defined as physical fuel, i.e. sun and wind are not fuels, while, e.g. urban waste must be described as a physical fuel instead of fuel replacement.

For each sector and fuel the various emissions are calculated using emission factors, and for each the annual costs are calculated of

- fuel
- operation and maintenance
- capital charge

The fuel and operation and maintenance costs are identical with the annual expenditure, while the capital charges are calculated from the investment costs of the various installations, each of which converted to an annuity over the lifetime of the installation using a 7 per cent interest rate.

7.2. Emissions

Table 7.1 shows the emission factors that were used for the study. These include emission factors for SO_2, NO_x, CO and particles at various fuel uses. Apart from particle emissions from power stations the same emission factors was used for the whole period up to the year 2000.

The emissions of SO_2 depends on the sulphur content of the fuel, and the emission factors must reflect the average sulphur contents of the fuels for the various uses. Abatement technologies like FGD will reduce the emission factors, but these was not included in this study.

The emissions of NO_x depend on the combustion technique and in particular the combustion temperature.

The emissions of CO also depend on the combustion technique. It is significant only in the transport sector.

Table 7.1. Emission factors, kg/GJ

	SO_2	NO_x	CO	Particles
Coal for power stations, 1982	0.717	0.40	0.02	0.12
Coal for power stations, 2000	0.717	0.40	0.02	0.02
Fuel oil for power stations	1.165	0.40	0.02	0.06
Small CHP station, gas motor		0.18		
Small CHP station, gas turbine		0.08		
District heating, coal	0.655	0.20	0.20	0.28
District heating, fuel oil 2.5% S	1.240	0.10	0.10	0.06
District heating, fuel oil 1.0% S	0.495	0.10	0.10	0.06
District heating, natural gas		0.10	0.10	
District heating, straw		0.36	0.36	0.57
District heating, urban waste	0.180	0.36	0.60	0.20
Individual oil furnace	0.235	0.14	0.02	
Individual gas furnace		0.15	0.15	
Individual straw furnace		0.36	0.36	0.57
Process, coal	0.655	0.28	0.08	0.08
Process, fuel oil	1.240	0.10	0.03	0.04
Process, gas/diesel oil	0.235	0.10	0.02	
Process, natural gas		0.10	0.10	
Process, petrol		0.09	0.02	
Transport, diesel oil	0.235	1.90	0.33	0.52
Transport, petrol		0.58	3.50	

Sources: Miljøstyrelsen (1984), and Dansk Kedelforening (1981)

The particle emissions depend on the fuel, the combustion technique and the abatement technology that is used. The emission factors in Table 7.1 represent today's average standards for power stations. However, new stations with more effective abatement technology are planned to penetrate.

Fig. 7.1 shows an example of the development in the emissions of SO_2 and NO_x to the year 2000 based on the official forecasts of

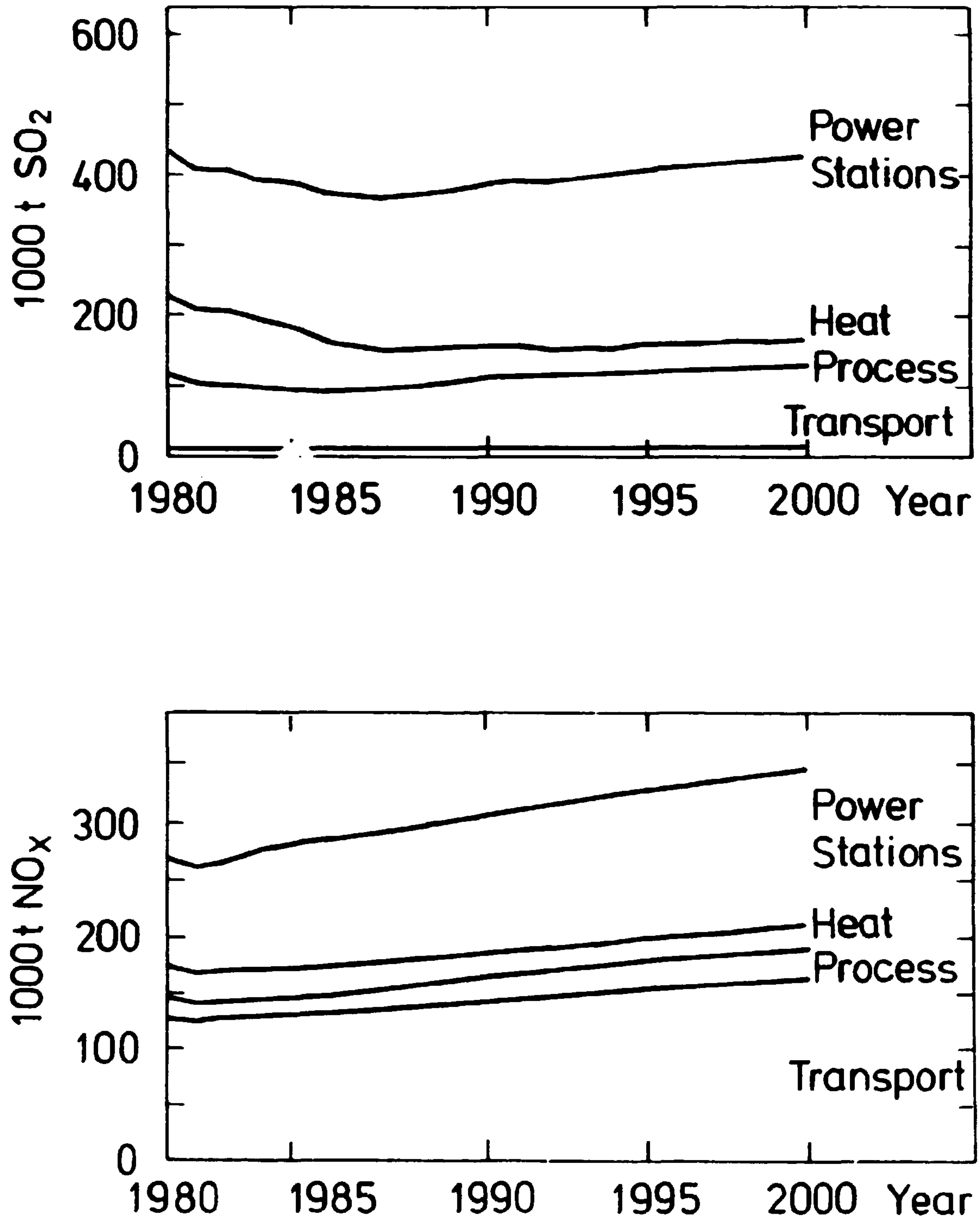

Fig. 7.1. SO_2- og NO_x emissions 1980-2000 (no abatement technologies used).

energy demand, fuel prices, and energy system development from 1983 (Ministry of Energy 1983). The calculation was made using the DES-Model, and it was provided that no further abatement technologies were used, i.e. the introduction of FGD, which was decided later, is not taken into account.

7.3. Energy system changes

A number of emission reduction measures was included in the study. For each type of measure a simplified economic assessment was made, in which a benefit of the reduced SO_2 emissions is taken into account using flue gas desulphurization (FGD) at large coal-fired power stations as a reference. These assessments were based on the available studies of various measures and technoligies. The measures include insulation of buildings, increased efficiencies of district heating grids, renewable energy, natural gas-fired CHP, more efficient use of electricity, etc.

Even though the avoided costs of FGD are small compared to fuel costs, and few measures not included in the official energy planning are economically attractive, the study shows, within the range of uncertainty, that there is a considerable potential for reduced emissions by measures that are economically acceptable.

The DES-Model was used to analyse the consequences of the implementation of these measures at national level. An example of the results is shown in Figs. 7.2 and 7.3.

It was assumed that all measures should be carried out during the period 1985 to 1994 with the same investment expenditures each year. The scenario includes the following measures:

- Retrofit insulation of roofs, cavity walls, and floors etc. in all buildings not conforming to a certain (high) insulation standard.

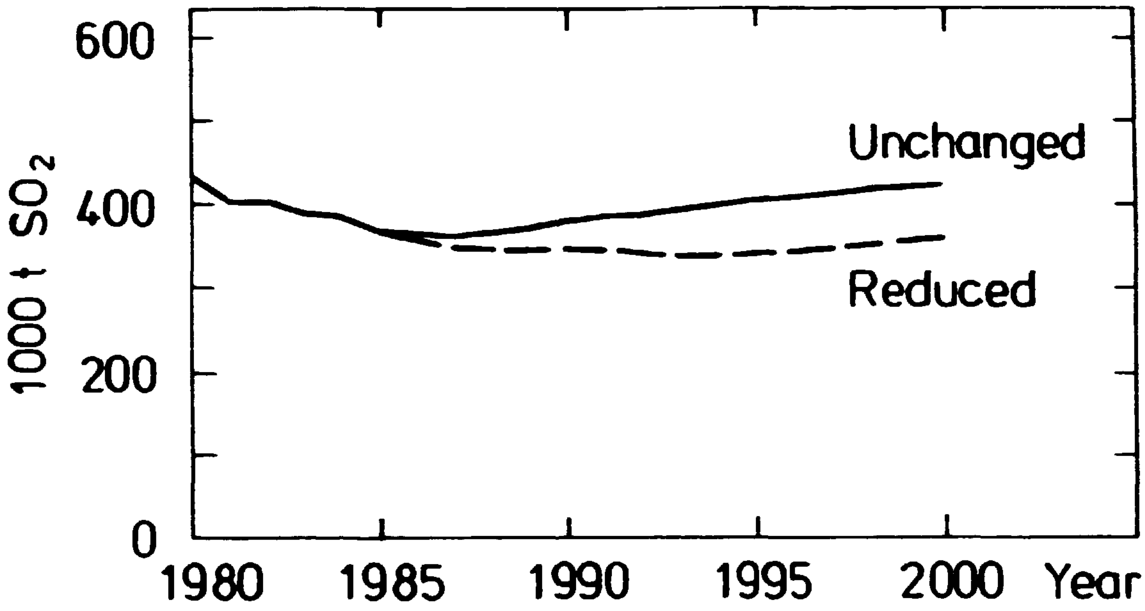

Fig. 7.2. Reduction of SO_2 emission by the example of energy system changes

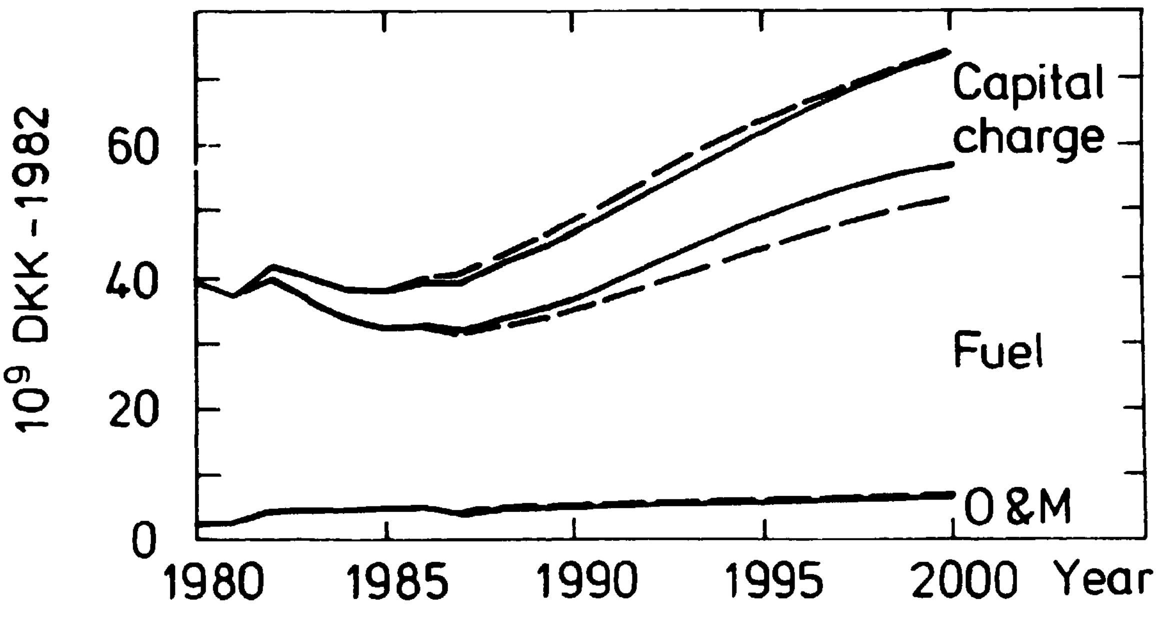

Fig. 7.3. Changes in energy system costs by the example of energy system changes

- Triple glazing in all buildings.
- Increased average efficiencies for district heating grids, radiator systems, and individual furnaces.
- Penetration of renewables corresponding the most extensive scenario in the Energy Plan 1981.
- Introduction of combined renewable energy systems for electricity and district heating in some 100 small villages without an existing district heating grid and in some 100 larger ones with a district heating grid.
- Extensive introduction of small natural gas-fired CHP-units.

These measures would necessitate changes in the official planning, e.g. smaller CHP supply from large power stations, less natural gas fired district heating, more single family dwellings with district heating, less coal-fired district heating plants, and less large power stations.

Compared to the base scenario the SO_2 emissions in the year 2000 will be reduced by 15 per cent and the NO_x emissions by 8 per cent; the total consumption of fossil fuels and the fuel costs will be reduced by about 10 per cent. These benefits will call for an increase in the investments in the energy sector over the years by more than one third.

The extra capital charge derived from the measures is calculated to 6 billion (10^9) DKK in the 2000 while the operation and maintenance costs remains nearly unchanged, and the fuel costs is reduced by 5 billion DKK. The net increase in energy system costs is thus about 1 billion DKK or 16 DKK per kg SO_2 which is not emitted. The latter figure is to be compared to the costs of the reference abatement measure - FGD at new power stations - which is set at 7 DKK per kg SO_2 not emitted.

These figures are of course very uncertain and highly sensitive to the particular assumptions that were made for the study. However, a conservative result of these model calculations is that a 10 to 15 per cent reduction in emissions and fuel costs may be obtained without excessive extra total costs through an appropriate combination of investments in these kind of measures and other modifications of the energy system.

REFERENCES

CHRISTENSEN, P.S., FENHANN, J., KILDE, N.A., LARSEN, J., MORTHORST, P.E. (1984). Den teknologiske udvikling og denne betydning for udformningen af det fremtidige energisystem. Risø, 312 pp + 2 app.

CHRISTENSEN, P.S., GROHNHEIT, P.E. (1983). The DES model - a simulation of the Danish Energy System. The Use of Simulation Models in Energy Planning. Proceedings of Risø International Conference 9-11 May 1983. Risø National Laboratory. pp. 181-196.

DANSK KEDELFORENING (1981). Forudsætninger for beregninger af emissionsforhold til EP81 (unpublished, 1981-12-17).

ELSAM (1984). Udvidelsesplan 84. Datagrundlag, Fredericia, Denmark.

ENERGIMINISTERIET (1981). Energiplan 81, Copenhagen. 179 pp. + appendices.

ENERGIMINISTERIET (1983). Energiplanlægning, Statusnotat 1983. Copenhagen. 61 pp.

ENERGIMINISTERIET (1984a). Energiplanlægning 1984, Copenhagen. 140 pp.

ENERGIMINISTERIET (1984b). Kul-Kernekraft. Forhold af betydning for electricitetsproduktion på basis af kul og uran, Copenhagen. 131 pp.

GROHNHEIT, P.E. (1984). Reduktion af SO_2- og NO_x-emissioner ved ændringer i energisystemet. Miljøstyrelsen juli 1984. 97 pp.

GROHNHEIT, P.E., and LAUT, P. (1986). Nuclear power and coal-fired CHP. Risø National Laboratory (submitted for publication).

LARSEN, HELGE V. (1984). Simulachron, A simulation model for a combined heat and power production system. Risø-R-508, Risø National Laboratory, Roskilde, Denmark. 155 pp.

MILJØSTYRELSEN (1984). Forsuringsprojektet: Emissionsbegrænsninger. Copenhagen. 254 pp.

MILJØSTYRELSEN FORSURINGSUDVALGET (1984). Miljø og energi. Copenhagen. 159 pp.

MINISTRY OF ENERGY (1983). Energy in Denmark. A Report on Energy Planning 1983. Copenhagen, 90 pp.

MINISTRY OF ENERGY (1984). Energy in Denmark. A Report on Energy Planning 1984. Copenhagen, 144 pp.

OECD/NUCLEAR ENERGY AGENCY (1983). The costs of generating electricity in nuclear and coal-fired power stations. A report by an Expert Group. Paris. 60 pp.

OECD/NUCLEAR ENERGY AGENCY (1985). The economics of the nuclear fuel cycle. Paris. 168 pp.

Sales distributors:
G.E.C. Gad Strøget
Vimmelskaftet 32
DK-1161 Copenhagen K, Denmark

Available on exchange from:
Risø Library, Risø National Laboratory,
P.O.Box 49, DK-4000 Roskilde, Denmark

ISBN 87-550-1224-8
ISSN 0106-2840